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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR APPROVAL OF THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC.	DOCKET NO. E-04204A-06-0783 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Ralph C. Smith (Redacted Version)(Consultant - Larkin & Associates, Inc.); David C. Parcell (Consultant – Technical Associates, Inc.); Alexander Ibhade Igwe (Utilities Division); Steve Taylor (Utilities Division); Julie McNeely-Kirwan (Utilities Division); and Bing E. Young (Utilities Division) in the above-referenced matter. An Unredacted version of Ralph C. Smith's Direct Testimony has also been provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 28th day of June 2007.

Arizona Corporation Commission
DOCKETED
JUN 28 2007
DOCKETED BY

Maureen A. Scott

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TESTIMONY

OF

RALPH C. SMITH
DAVID C. PARCELL
ALEXANDER IBHADE IGWE
STEVE TAYLOR
JULIE MCNEELY-KIRWAN
BING E. YOUNG

DOCKET NO. E-04204A-06-0783

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING

JUNE 28, 2007

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED. FINANCING	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

My testimony addresses the following issues:

- The Company's proposed revenue requirement.
- Adjustments to test year data
- Rate base, including construction work in progress
- Test year revenues (including number of customers and usage) and expenses.
- Depreciation rates
- The Company's requested modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC") and Staff's recommendations for features to include in a new PPFAC for UNS Electric
- The Company's proposed ratemaking treatment for a new peaking unit, the Black Mountain Generating Station ("BMGS")

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of $8.5 million is overstated. I recommend that UNS Electric be authorized a base rate increase of $3.802 million on adjusted fair value rate base.

- The following adjustments to UNS Electric's proposed original cost and fair value rate base should be made:

Summary of Staff Adjustments to Rate Base		**Original Cost**		**Fair Value**	
Adj. No.	Description		Increase (Decrease)		Increase (Decrease)
B-1	Remove Construction Work in Progress	$	(10,761,154)	$	(10,761,154)
B-2	Adjust CWIP for Plant in Service by End of Test Year	$	442,255	$	442,255
B-3	Plant in Service Addition Subject to Reimbursement	$	(236,874)	$	(236,874)
B-4	Cash Working Capital - Lead/Lag Study	$	197,541	$	197,541
B-5	Accumulated Deferred Income Taxes	$	(161,555)	$	(161,555)
	Total of Staff Adjustments	**$**	**(10,519,787)**	**$**	**(10,519,787)**
	UNS Proposed Rate Base	$	140,991,324	$	177,802,341
	Staff Proposed Rate Base	**$**	**130,471,537**	**$**	**167,282,554**

- The following adjustments to UNS Electric's proposed revenues, expenses and net operating income should be made (amounts shown are impact on net operating income):

Summary of Staff Adjustments to Net Operating Income

Adj. No.	Description	Increase (Decrease)
C-1	Revenue Adjustment for CARES Discount	$ 32,504
C-2	Remove Depreciation & Property Taxes for CWIP	$ 423,374
C-3	Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year	$ (16,322)
C-4	Fleet Fuel Expense	$ 43,221
C-5	Postage Expense	$ (10,747)
C-6	Normalize Injuries and Damages Expense	$ 97,668
C-7	Incentive Compensation Expense	$ 27,017
C-8	Supplemental Executive Retirement Plant (SERP) Expense	$ 51,274
C-9	Stock Based Compensation Expense	$ 50,886
C-10	Property Tax Expense	$ 36,686
C-11	Rate Case Expense	$ 68,566
C-12	Edison Electric Institute Dues	$ 5,201
C-13	Other Membership and Industry Association Dues	$ 3,980
C-14	Interest Synchronization	$ (181,343)
C-15	Depreciation Rates Correction	$ 38,748
C-16	Emergency Bill Assistance Expense	$ (12,280)
C-17	Markup Above Cost in Charges from Affiliate, SES	$ -
Total of Staff's Adjustments to Net Operating Income		**$ 658,432**
	Adjusted Net Operating Income per UNS Gas	$ 8,742,011
	Adjusted Net Operating Income per Staff	$ 9,400,443

- The new depreciation rates proposed by UNS Electric presented in Dr. White's direct testimony Attachment REW-2 should be adopted for use in this case, as corrected in the response to data request STF 11.8. The depreciation rates proposed by UNS Electric were generally developed in a manner that is consistent with the Commission's rules for depreciation rates.

- Each of the new depreciation rates proposed by UNS Electric should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

- The new PPFAC proposed by UNS Electric contains objectionable features such as automatically adjusting rates without Commission review and inclusion of costs that would more appropriately be addressed in base rates, as well as raising other concerns, and should therefore be rejected. A new PPFAC for UNS Electric should be developed along the lines of the APS PSA Plan of Administration Staff proposed for the Arizona Public Service Company in Docket Nos., E-01345A-05-0816 et al, after appropriate adjustments to fit UNS Electric's circumstances. The new PPFAC for UNS Electric should become effective June 1, 2008, upon expiration of the Company's all requirements power contract with PWCC.

- The Black Mountain Generation Station ("BMGS") is a 90 MW peaking plant which is being constructed in Mohave County by an affiliate, and which the Company projects will be in service around June 1, 2008 when the PWCC PSA expires. The in-service date for this plant is too far outside of the test year to qualify for base rate treatment in the current UNS Electric rate case. Staff believes that a more reasonable alternative approach to addressing the ratemaking and cash flow impacts of meeting UNS Electric's power supply will need to be developed. UNS Electric's proposed base rate treatment for BMGS in the current case should be rejected for the reasons described in my testimony, including the uncertainties presently existing with respect to this plant.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 27 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorney generals, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, Washington D.C., and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on a number of occasions. Recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company"), and concerning APS's proposed depreciation rates in Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, a proceeding involving APS base rates and other matters. I also testified before the Commission in the most recent UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-01013 and G-04204A-05-0831.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the revenue requirement and selected other issues, including new depreciation rates, changes to the Purchased Power and Fuel Adjustment Clause ("PPFAC") proposed by UNS Electric, Inc. ("UNS Electric" or "Company"), and the Company's proposed ratemaking treatment for a new peaking unit, the Black Mountain Generating Station ("BMGS") in the current rate case.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-5 contain the results of my analysis and copies of selected documents that are referenced in my testimony.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by UNS Electric?

A. UNS Electric is requesting an increase in base rate revenues of $8.507 million, or approximately 5.5 percent. UNS Electric witness James Pignatelli's direct testimony at pages 3-5 attributes the need for the requested increase primarily to increased growth in UNS Electric's service territory and the related increases in capital expenditures and operating costs.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of $3.802 million on adjusted fair value rate base. As shown on Schedule A, the comparable base rate revenue increase calculated by Staff on original cost rate base is $3.801 million.

A. Test Year

Q. What test year is being used in this case?

A. UNS Electric's filing is based on the historic test year ended June 30, 2006. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Summary of Company Proposed and Staff Adjusted Revenue Requirement

Q. What did your review of UNS Electric's filing indicate?

A. As shown on Schedule A, based on the rate of return recommended by Staff witness Parcell and the adjustments to UNS Electric's rate base and net operating income recommended by myself and other Staff witnesses, I have calculated a revenue requirement deficiency of $3.802 million for UNS Electric. I recommend a revenue increase of $3.802 million on adjusted fair value rate base. As shown on Schedule A, the comparable base rate revenue increase calculated by Staff on original cost rate base is $3.797 million.

C. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-5 and net operating income adjustment Schedules C-1 through C-17.[1]

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. The schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on original cost rate base of 8.99%, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience. Schedule D uses the capital structure and cost rates recommended in the prefiled testimony of Mr. Parcell. The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the

[1] Schedule C-17 has been reserved for a potential adjustment for charges to UNS Electric from an affiliate Southwest Energy Services, pending receipt of the information requested in data request STF 15.1.

income deficiency by the gross revenue conversion factor (GRCF). The derivation of the GRCF is shown on Schedule A-1.

Q. What is shown on Schedule B?

A. Page 1 of Schedule B presents UNS Electric's proposed adjusted test year Original Cost and Fair Value rate base and Staff's proposed adjusted test year Original Cost and Fair Value rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically UNS Electric Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is UNS Electric's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to UNS Electric's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments are discussed in this testimony. Schedules C-1 through C-16 provide further support and calculations for the net operating income adjustments I am recommending.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by UNS Electric and the capital structure and cost of capital that is recommended by Staff witness Parcell. Schedule D also presents the derivation of Staff's recommended cost of capital for use with the Staff's adjusted fair value rate base.

D. Return on Fair Value Rate Base

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the fair value rate base was determined by averaging Original Cost and reconstruction cost new depreciated (RCND) rate base information. For purposes of this presentation, I have used the Company's RCND information as the starting point for the fair value rate base. However, using such RCND information for a utility that was recently purchased in an arms' length transaction at a substantial discount to book value could result in substantially overstating the fair value rate base.

Q. Please explain how using the RCND information presented by UNS Electric could result in substantially overstating the fair value rate base.

A. UNS acquired the electric utility from Citizens Communications in August 2003. As of August 11, 2003, the date of the acquisition, the fair value of the assets acquired from Citizens would be equal to the purchase price paid by UniSource.[2] The acquisition of the electric utility was the result of an arm's length transaction between a willing and informed buyer and a willing and informed seller.[3] Reconstructed cost new ("RCN") information, reconstructed cost new depreciated ("RCND") information, Handy-Whitman Index information, Marshall Index information, and Bureau of Labor Statistics index information was given little or no weight by UniSource in deciding how much to pay for the electric utility.[4] The arm's length transaction that has occurred demonstrates that the RCND was not a good estimate of the "fair value" for this utility as of the date of the acquisition. The price paid in the arm's length transaction would represent the "fair value" of the utility as of the date of acquisition. The price paid was substantially below

[2] See response to STF 3.87a
[3] Response to STF 3.87b.
[4] Response to STF 3.87c.

the original cost depreciated book value. Because the acquisition occurred fairly recently (August 11, 2003), this suggests that using RCN and RCND information to establish the fair value of the utility rate base in the current case could result in a substantial overstatement of fair value rate base.

Q. How did UNS Electric determine the rate of return to apply to fair value rate base in its filing?

A. In UNS Electric's own filing, as shown on Schedule A-1, the Company adjusted the return that is to be applied to fair value rate base downward, consistent with long-standing Commission practice, such that the revenue requirement produced by both the original cost rate base and the fair value rate base would not result in an excessive return on equity to the utility. UNS Electric's calculation of return on fair value rate base in the instant case is also consistent with the way the return was applied to the fair value rate base in the original rate case filing of its affiliate, UNS Gas, in Docket No. G-04204A-06-0463.

Q. Has the Commission's traditional calculation of return on fair value rate base been called into question by a recent Court of Appeals decision?

A. Yes. The Commission's traditional calculation of return on fair value rate base calculation has been called into question by a recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In that ruling, the Arizona Court of Appeals found that Staff's determination of operating income ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

Q. What guidance for calculating the return on fair value rate base does that Court of Appeals decision provide?

A. First, the Court of Appeals specifically stated that the Commission was <u>not</u> bound to apply an authorized rate of return that was developed for use with an original cost rate base, without adjustment, to the fair value rate base. Page 9 of the Court of Appeals decision stated that: "Chaparral City ... asks that the Commission be directed to apply the 'authorized rate of return' to the fair value rate base rather than to the OCRB, as Chaparral City contends was done here." At page 13, paragraph 17, the Court of Appeals decision states as follows: "The Commission asserts that it was not bound to use the weighted average cost of capital as the rate of return to be applied to the FVRB. The Commission is correct." Thus, the Court of Appeals clearly stated that the Commission is <u>not</u> bound to apply to the FVRB the same weighted average cost of capital that was developed for application to the OCRB.

At pages 13-14, paragraph 17, the Court of Appeals decision stated that: "... the Commission cannot ignore its constitutional obligation to base rates on a utility's fair value. The Commission cannot determine rates based on the original cost, or OCRB, and then engage in a superfluous mathematical exercise to identify the equivalent FVRB rate of return. Such a method is inconsistent with Arizona law." At page 13, the decision states: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

Q. Has a remand proceeding been established by the Commission to address the calculation of the return on fair value rate base, i.e., to address the ruling in the Court of Appeals decision?

A. The Commission has opened a docket to address such issues in a Chaparral City remand proceeding.

Q. Did UNS Electric address the Chaparral decision in its Direct Testimony in this case?

A. No. The Company's Direct Testimony was filed on December 15, 2006 and the Court of Appeals' ruling in Chaparral City was issued on February 13, 2007. However, in the recent UNS Gas case, at page 28 of his rebuttal testimony, Mr. Grant, the Company's cost of capital witness, presented a new position concerning the return on fair value rate base calculation that was based on his "non-legal understanding" of the recent Arizona Court of Appeals ruling involving Chaparral City Water Company. In the UNS Gas case, Mr. Grant's recommended that, as a result of that ruling, the weighted cost of capital that was developed for use with an original cost rate base, should be applied without adjustment to the fair value rate base. As described in my surrebuttal testimony in the UNS Gas case, Staff strongly disagreed with that recommendation by Mr. Grant.

Q. How has Staff addressed the ruling in the Court of Appeals decision for purposes of the current UNS Electric rate case?

A. In view of the Court of Appeals decision in the Chaparral City case and the Company's position in the UNS Gas case, Staff has appropriately adjusted the weighted cost of capital to the utility's fair value rate base. David Parcell's direct testimony in the instant rate case describes Staff's revision to the return on fair value rate base calculations in view of the recent Court of Appeals decision concerning Chaparral. Staff will also be addressing the return on fair value calculation in the Chaparral City remand proceeding.

On Schedule D of Exhibit RCS-2, I have derived the adjusted weighted cost of capital for application to the FVRB. On Schedule A of that exhibit I have applied Staff's adjustment to the weighted cost of capital as described by Mr. Parcell in his direct testimony. As shown on Exhibit RCS-2, Schedule A, the application of Staff's adjusted weighted cost of capital to the FVRB results in revenue increase of $3.8 million. In this instance, the application of the adjusted weighted cost of capital to the FVRB produces a slightly higher revenue requirement than does the application of the unadjusted rate of return to OCRB.

III. RATE BASE

Q. Have you prepared a schedule that summarizes staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to UNS Electric's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

Summary of Rate Base	UNS Electric	Staff	Difference
Original Cost Rate Base	$ 140,991,324	$ 130,470,748	$ (10,520,576)
Fair Value Rate Base	$ 177,802,341	$ 167,281,765	$ (10,520,576)

The vast majority of the difference between the Company's proposed and Staff's recommended rate base relates to whether Construction Work in Progress should be included in rate base or not.

B-1 Construction Work in Progress

Q. Please explain the adjustment shown on Schedule B-1.

A. UNS Electric has proposed to include $10.8 million of Construction Work in Progress ("CWIP") in rate base. Staff adjustment B-1 removes that amount of CWIP from rate base.

Q. Please discuss UNS Electric's reasons for requesting the inclusion of CWIP in rate base.

A. As described in the testimony of UNS Electric witness Kentton Grant, the Company believes that inclusion of CWIP in rate base is necessary to preserve the financial integrity of the Company. Mr. Grant indicates that, as reflected in the Company's rate application, rate base treatment of the $10.8 million test year CWIP balance provides UNS Electric with approximately $2.1 million in additional annual revenues. He states that denial of this requested rate treatment would have a material adverse impact on the Company's rate relief and future earnings, and would make it difficult for the Company to attract new capital on reasonable terms. The Company has been experiencing robust growth and expects to need access to outside capital to fund system growth and capital improvements. Mr. Grant also states that inclusion of CWIP in rate base is one of the few available tools to help mitigate the effects of regulatory lag. He suggests further that, by including CWIP in rate base in this proceeding, the time period between this rate case and the next rate filing by UNS Electric will hopefully be extended. He indicates that if the Company's proposed rate base treatment of CWIP is denied, the authorized rate of return should be increased, and the Commission should consider an adjustment for plant placed into service after the test year. He points out that the Commission has, on occasion, allowed the inclusion of post test year plant in rate base.

Q. Is inclusion of CWIP in rate base up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base.

Q. Does Staff agree with the proposal of UNS Electric to include CWIP in rate base in the current case?

A. No. In general, Staff does not favor inclusion of CWIP in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment. For a number of reasons, including the following, Staff does not support UNS Electric's request for rate base inclusion of CWIP in the current case:

1) Inclusion of CWIP in rate base is an exception to the Commission's normal practice, and UNS Electric has not met its burden of proof showing why it requires such an exceptional ratemaking treatment.
2) The CWIP was not in service at the end of the test year. As of June 30, 2006, the construction projects were not serving customers.
3) The Company has not demonstrated that its June 30, 2006 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for plant related to serving customer growth, i.e., to be revenue producing. Test year revenues have been annualized to year-end customer levels. However, revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports, would be imbalanced.
4) While the Company has stated that inclusion of CWIP in rate base could result in deferring the filing of its next rate case, the Company has made no specific enforceable commitments to a filing moratorium period.

Q. Please elaborate on how including CWIP in rate base is an exceptional ratemaking treatment and why the circumstances in this case do not warrant such treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in providing electric service to the Company's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current UNS Electric rate case, the test year is the twelve months ending June 30, 2006, and the construction projects the Company seeks to include in rate base were not providing service during that period. As a general ratemaking principle, such CWIP should be excluded from rate base.

Furthermore, some of the facilities that are being constructed and are included in CWIP will be used subsequent to the test year to serve additional customers. It would not be appropriate to include the investment that will serve those new customers without also including the revenues that would be received from those customers. In other words, allowance of CWIP in rate base would result in a mismatch in the ratemaking process. Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test period. The inclusion of CWIP in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, CWIP should not be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule. In the current case, UNS Electric has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base. It is not appropriate to include the CWIP in rate base, particularly as the projects may result in additional revenues or cost savings which have not been reflected in the test year.

Q. How does UNS Electric accrue a return on construction projects?

A. UNS Electric accrues a return, representing its financing costs during the construction period in an account called Allowance for Funds Used During Construction ("AFUDC"). This AFUDC return accounts for the utility's financing cost during the construction period. Then, when the plant is placed into service, the AFUDC becomes part of the cost of the plant and is depreciated.

Q. If CWIP were to be included in rate base, as requested by the Company, what is UNS Electric's position concerning whether the accrual of AFUDC should cease?

A. This issue is addressed in Mr. Grant's direct testimony at page 30. Mr. Grant recognizes that "the accounting guidelines published by the FERC require utilities to subtract the amount of any CWIP allowed in rate base from the balance of future CWIP eligible for AFUDC accruals." However, he then attempts to carve out an exception for UNS Electric to this required accounting for AFUDC. He states that, because there is only a small amount of AFUDC on the test year balance of CWIP, it would be unfair to require UNS Electric to cease accruing AFUDC on $10.8 million of CWIP on an ongoing basis. He requests that, if the Commission grants the Company's request to include CWIP in rate base, that language be included in the order that authorizes the Company to continue accruing AFUDC on all eligible construction projects.

Q. Does Staff agree with this proposal by Mr. Grant to continue accruing AFUDC even if CWIP were to be included in rate base?

A. No. Mr. Grant's proposal to continue accruing AFUDC on CWIP should be rejected because it is contrary to the accepted accounting guidelines and would result in a double recovery of the financing cost of CWIP. The financing cost for CWIP can be addressed for ratemaking purposes in one of two ways: (1) through the inclusion of CWIP in rate base for a current cash return, or (2) through the accrual of AFUDC, which is added to the construction cost and is ultimately included in the cost of plant and depreciated. It would be improper to give UNS Electric both a cash return on CWIP through its inclusion in rate base and an AFUDC return. If CWIP were to be allowed in rate base, which the Staff is not recommending in this case, then AFUDC accruals on the amount of CWIP included in rate base must cease.

Q. Does Staff agree with UNS Electric's alternative proposal to include post-test year plant additions in rate base, if the inclusion of CWIP in rate base is denied?

A. No. For similar reasons to those described above, Staff does not agree with UNS Electric's proposed alternative of including post-test year plant in rate base.

Q. How does plant that is placed into service between rate case test years typically get reflected in the regulatory process?

A. If the plant is used to serve new customers, the utility receives revenue from those customers. If the plant helps the utility reduce expenses, such as maintenance, the utility benefits from such cost reductions during the intervening period. Once the plant is recognized in rate base in a test year, and rates are reset, the utility earns a cash return on the plant investment, less accumulated depreciation. The related revenues and expense impacts, including known and measurable expense reductions enabled by the plant, are then also recognized in the ratemaking process.

Q. Is another witness for Staff addressing certain aspects of UNS Electric's request for inclusion of CWIP in rate base?

A. Yes. Staff's rate of return witness, David Parcell, is addressing the determination of a fair rate of return that would allow UNS Electric to attract new capital on reasonable terms. In making his cost of capital recommendations, Mr. Parcell has been made aware of and has taken into consideration UNS Electric's proposal to include CWIP in rate base and Staff's recommendation that CWIP not be included in rate base in this case.

Q. Does Staff's adjustment to remove CWIP from rate base affect UNS Electric's expenses?

A. Yes. UNS Electric had proposed to treat CWIP at the end of the test year as if it were plant in service. Consistent with that, UNS Electric proposed increases to depreciation and property tax expense. Consistent with Staff's recommendation that CWIP not be included in rate base, Staff adjustment C-2, which is described in a subsequent section of my testimony, removes the related UNS Electric adjustments for depreciation and property tax expense.

B-2 Adjust CWIP for Plant In Service by End of Test Year

Q. Please explain Staff's adjustment to CWIP for Plant In Service by the end of the test year.

A. The results of Staff's preliminary field assessment of used and useful review for UNS Electric indicated that one project included in CWIP, Rhodes Homes (task 8009729), with a cost of $442,255 and inspected by Staff on June 6, 2007, was in service on May 26, 2006, which was prior to the end of the test year. This project involved the installation of five miles of 21 kV overhead line to supply service to water pumps for a proposed housing development. For ratemaking purposes, this project should be treated as plant in service because it was in service by the end of the test year. Accordingly, Staff adjustment B-2, adds the $442,255 to rate base as plant in service.

Q. Were there Customer Advances associated with this plant?

A. Yes. Staff's preliminary field assessment indicates that the project is fully funded initially by the customer, Rhodes Homes. A March 2, 2006 Letter of Agreement indicates that the customer will pay to the Company a total Customer Advance of $360,117.

Q. How have the Customer Advances related to this project been reflected for ratemaking purposes?

A. The Company's response to data request STF 15.4(f) indicates that, as of June 30, 2006, UNS Electric had received Customer Advances totaling $360,117 for this project. The Company's response to data request STF 15.4(g) indicates that no additional Customer Advances for this project were received after June 30, 2006. Thus, it appears that the Customer Advances amount related to this project of $360,117 would have already been reflected as such by the Company in its proposed rate base. Consequently, based on the information provided by the Company to date, no additional pro forma adjustment for the Customer Advances related to this project appears to be necessary.

B-3 Plant in Service Addition Subject to Reimbursement

Q. Did Staff's field assessment reveal any other concerns?

A. Yes. Staff's inspection of the Tubac Golf Resort Overhead to Underground Conversion (task CE64023) with a cost of $236,874 had the appearance of a project that should be reimbursed, at least in significant part by the customer, since it involved the removal of an overhead 13 kV line and installation. UNS Electric advised Staff that the project appeared to be reimbursable to some extent, but was not able to provide documentation of the customer reimbursement. This project should be removed from rate base unless UNS Electric provides sufficient documentation to prove that inclusion is appropriate. The Company's response to STF 15.4(d) states that: "this customer requested work was paid 100% by the customer as a Contribution in Aid of Construction." It was unclear from that response whether the CIAC had been received and recorded by UNS Electric as of June 30, 2006, the end of the test year. If the CIAC had been recorded by UNS Electric by June 30, 2006, the adjustment shown on Schedule B-3 would not be necessary. If the CIAC was received and recorded by UNS Electric after June 30, 2006, the adjustment shown on Schedule B-3 is necessary to properly reflect the Company's net investment in the project, which would be zero, since the project was paid 100 percent by the customer. Depending on when UNS Electric received and recorded the CIAC related to this project, a related pro forma adjustment to Depreciation Expense may also be needed.

B-4 Cash Working Capital

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's working capital request consists of three separate subcomponents. The subcomponents are: (1) a negative cash working capital balance of $2.635 million based on a lead/lag study; (2) a thirteen-month average materials and supplies balance of $5.651 million; and (3) a thirteen-month average prepayments balance of $351,825. As shown on Company Schedule B-5, UNS Electric's rate base reflects a request for working capital of negative $3.368 million. I will address the Company's cash working capital request, along with the lead/lag study UNS Electric provided as support for that request.

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does UNS Electric have a positive or negative cash working capital requirement?

A. UNS Electric has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did UNS Electric present a lead/lag study in support of its cash working capital requirement?

A. Yes, UNS Electric performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Has UNS Electric made any revisions to the cash working capital calculation included in its filing?

A. No, none of which I am aware.

Q. Are you recommending any revisions to UNS Electric's cash working capital request?

A. Yes. I have reflected the impact of Staff's adjustments to operating expenses and impacts on revenue based taxes. I have also synchronized the calculation with cash working capital with Staff's recommended revenue increase.

Q. What is the result of your cash working capital calculation?

A. As shown on Schedule B-4, UNS Electric's filed cash working capital request should be increased by approximately $197,000.

B-5 Accumulated Deferred Income Tax

Q. Please explain the adjustment to Accumulated Deferred Income Taxes ("ADIT").

A. This adjustment is shown on Schedule B-5, and decreases rate base by $161,555 for the impact of the following:

1) removal of the ADIT related to the Supplemental Executive Retirement Plan ("SERP")[5]; and
2) removal of the ADIT relating to stock-based compensation.[6]

This adjustment to ADIT is necessary to properly coordinate the impact of Staff's related adjustments to operating expenses with the ADIT amount included in rate base.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C summarizes Staff's recommended net operating income. Schedule C.1, present Staff's recommended adjustments to test year revenues and expenses on an

[5] See Staff Adjustment C-8 that has removed the expense related to SERP.
[6] See Staff adjustment C-9 that removes the expense for stock-based compensation.

Arizona jurisdictional basis. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. UNS Electric's proposed adjusted test year net operating income is $8.742 million, whereas Staff's recommended adjusted net operating income is $9.406 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 Revenue Adjustment for CARES Discount

Q. Please explain Staff Adjustment C-1.

A. This adjustment removes UNS Electric's proposed adjustment to reduce electric retail revenue by $52,937 relating to a change proposed by the Company concerning how the discounts for CARES customers are calculated. As explained in the testimony of Staff witness Julie McNeely-Kirwan, Staff disagrees with that Company proposal and recommends that the existing discount rate structure for CARES be retained. It is anticipated that Staff will present further details concerning the rate design impacts of its CARES discount recommendations when Staff files its rate design testimony on July 12, 2007.

C-2 Remove Depreciation and Property Taxes for CWIP

Q. Please explain Staff Adjustment C-2.

A. This adjustment removes the pro forma amounts calculated by UNS Electric for depreciation and property taxes related to the Company's proposal to include CWIP in rate base. As explained above[7], Staff disagrees with the Company's proposal to include CWIP in rate base. Accordingly, Staff has also removed the pro forma depreciation and property tax expense adjustments proposed by UNS Electric. As shown on Schedule C-2, this

[7] See above discussion in conjunction with Staff Adjustment B-1.

reduces the Company's proposed expenses for depreciation by $449,816 and property taxes by $239,696, for a total reduction of $689,512.

C-3 Depreciation and Property Taxes for CWIP Found to Be In-Service in the Test Year

Q. Please explain Staff adjustment C-3

A. This adjustment relates to rate base adjustment B-2. As described above in conjunction with Staff adjustment B-2, Staff's engineering and used-and-useful review revealed that a project that UNS Electric had included in CWIP was actually in service in May, 2006, and thus qualifies as plant in service. This adjustment increases recorded test year expenses to provide for depreciation and property taxes related to a project that UNS Electric had included in CWIP, Rhodes Homes (task 8009729), with a cost of $442,255 that was inspected by Staff on June 6, 2007, and was found to be in service on May 26, 2006, which was prior to the end of the test year. As shown on Schedule C-3, this Staff adjustment increases depreciation expense by $18,265 and property tax expense by $8,317 to reflect the annualized depreciation and property taxes on this item of plant, the Rhode Homes overhead line extension project, that was in service by the end of the test year.

C-4 Fleet Fuel Expense

Q. Please explain Staff Adjustment C-4.

A. This adjustment reduces the Company's proposed post-test year increase for vehicle fleet fuel expense. Staff's adjustment used the weighted average cost per gallon of fuel expense from the three primary suppliers through May 2007, which reflects an average cost per gallon of $2.69. Staff's adjustment follows a similar format to the UNS Electric proposed adjustment for fleet fuel expense. Staff's adjustment allows for a pro forma fuel expense increase of $3,270 based on a cost of gasoline of $2.69 based on UNS Electric's actual fuel costs. UNS Electric's proposed adjustment is reduced by $70,391, as shown on Schedule C-4.

C-5 Postage Expense

Q. What has UNS Electric proposed for normalized postage expense?

A. UNS Electric has proposed normalized postage expense of $341,321. This is shown on in UNS Electric's workpaper for the Company's proposed postage expense adjustment.

Q. Does the UNS Electric-proposed amount of normalized postage expense reflect the postage rate increase that became effective on May 14, 2007?

A. No. That increase is now known and should be reflected, similar to a known change in tax rates. This postage rate increase has occurred and should be recognized for ratemaking purposes. To derive the adjustment to annualized postage expense to reflect the May 14, 2007 increase, which increased the cost of a first class letter from 39 cents to 41 cents (for an increase of 5 percent), Staff has increased the Company's proposed postage expense by 5 percent. As shown on Schedule C-5, this increases UNS Electric's proposed amount of postage expense by $17,503.

C-6 Normalize Injuries and Damages Expense

Q. Please explain Staff Adjustment C-6.

A. This adjustment normalizes the amount of Injuries and Damages Expense, based on a three-year average through December 2006. As shown in the following table, the amount proposed by UNS Electric is substantially higher than the corresponding amount in each calendar year during UNS Electric's ownership of the utility:

Staff adjustment C-6 reduces test year expense by $159,063.

UNS Electric Injuries and Damages Expense

Test Year Ending 6/30/06	$ 562,403		
Comparable Information:			
Year	Annual Expense	Exceeds Annual Expense By $	Exceeds Annual Expense By %
2004	$ 352,589	$ 209,814	59.5%
2005	$ 356,992	$ 205,411	57.5%
2006	$ 500,440	$ 61,963	12.4%
Average	$ 403,340	$ 159,063	39.4%

Source: Response to data request STF 3.101

Q. **Why is the test year Injuries and Damages expense so high in comparison with the other years?**

A. The test year Injuries and Damages expense (Account 925) is so high in comparison with the other years because a number of the types of expenses which are recorded in this account appear to be abnormally high in the test year, and would thus require separate adjustment, if the balance in this account were not normalized, as described above. As one illustrative example, the Company's response to data request STF 11.16 indicates that worker's compensation expense in the test year was $190,028. This test year amount exceeded the 2006 recorded amount and the average for 2004-2006 by approximately $93,000, as summarized in the following table:

UNS Electric Workers Compensation Expense

Test Year Ending 6/30/06	$ 190,028		
Comparable Information:			
Year	Annual Expense	Exceeds Annual Expense By $	Exceeds Annual Expense By %
2004	$ 129,454	$ 60,574	46.8%
2005	$ 57,111	$ 132,917	232.7%
2006	$ 93,869	$ 96,159	102.4%
Average	$ 93,478	$ 96,550	103.3%

Source: Response to data request STF 11.16

Additionally, the Company's expense for Directors' and Officers' Liability ("D&O") Insurance is recorded in Account 925 and has been increasing substantially, from $22,032 in 2004, to $88,605 in 2005, to $130,330 in 2006, as listed in the responses to data requests STF 3.102 and STF 11.15. The substantially increased cost of such D&O insurance is a concern because the direct monetary benefits of D&O Insurance flow to shareholders. The monetary benefit from D&O Insurance is not enjoyed by ratepayers. Because shareholders benefit materially from this insurance, it may be appropriate to allocate the cost of D&O Insurance equally between shareholders and ratepayers.

In summary, Staff Adjustment C-6 to normalize the expense in Account 925 as shown on Schedule C-6 is believed to be a reasonable approach. By adjusting the total in this account to a normalized level, the additional adjustments that would otherwise appear to be needed to address specific components of the expenses recorded in the account are rendered unnecessary.

C-7 Incentive Compensation

Q. Please explain Staff Adjustment C-7.

A. This adjustment removes 50% of the expense related to the various incentive compensation programs in effect at UNS Electric. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

The adjustments to expense for each of UNS Electric's incentive compensation programs are shown on Schedule C-7. The adjustment reduces O&M expense by $42,448. A related impact on payroll tax expense reduces that by $1,553.

Q. Please discuss the UniSource Energy Corporation's Performance Enhancement Program.

A. UNS Electric participates in the same incentive compensation arrangement, the Performance Enhancement Plan ("PEP"), as its affiliate, UNS Gas. As explained in the Company's supplemental response to data request STF 11.5 in the recent UNS Gas rate case, Docket Nos. G-04204A-06-0463 et al, the utility's non-union employees participate in UniSource Energy Corporation's PEP. UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Corporation and the parent company of UNS Electric. The structure of the PEP determines eligibility for certain bonus levels by measuring UES' performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout. The amount made available for bonuses pursuant to the PEP formula may range from 50 percent to 150 percent of the targeted payment level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

As explained in the Company's supplemental response to data request STF 11.5(c) in the recent UNS Gas rate case, Docket G-04204A-06-0463:

> "In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Electric financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in the response to STF 11.5 b, the 2005 primary financial goal was not met."

Q. Even though the primary financial goal under the PEP was not met in 2005, were incentive bonuses paid?

A. Yes, they were. As explained in the utility's supplemental response to STF 11.5(b): in the recent UNS Gas rate case, Docket No. G-04204A-06-0463, which describes the same UniSource Energy PEP in which UNS Electric also participates:

> "... the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Electric and Tucson Electric Power Company ("TEP"), was not met. The financial performance goal was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Aware was paid at approximately 42% of the target for each of the operating companies."

C-8 Supplemental Executive Retirement Program Expense

Q. Please explain Staff Adjustment C-8.

A. This adjustment removes 100% of the expense for the Supplemental Executive Retirement Plan ("SERP"). The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Are you aware of any recent Commission decisions that reached similar conclusions regarding the appropriate ratemaking treatment of incentive compensation and SERP expense?

A. Yes. As an illustrative example, in Decision No. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted Staff's recommendation for an equal sharing of costs associated with that utility's management incentive plan compensation expense, and adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> "Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to

> remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers."

Q. What adjustment related to UNS Electric's SERP expense do you recommend?

A. I recommend the adjustment to remove UNS Electric's expense for the SERP, which is shown on Schedule C-8 and reduces O&M expense by $83,506.

C-9 Stock Based Compensation

Q. Please explain Staff Adjustment C-9.

A. This adjustment decreases test year expense by $82,873 for the removal of stock-based compensation to officers and employees. The expense of providing stock options and other stock-based compensation to officers and employees beyond their normal levels of compensation should be borne by shareholders and not by ratepayers.

C-10 Property Tax Expense

Q. Please explain Staff Adjustment C-10.

A. This adjustment reflects the known statutory assessment ratio of 23.5 percent applicable for 2008, when rates in this case are expected to become effective. The Arizona State Legislature passed House Bill No. 2779 which set a new rate schedule for property tax assessments. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 in 0.5 percent steps each year until a 20 percent rate is attained in 2015. The Company's calculation used a 24 percent assessment rate and thus fails to recognize the impact of this known tax change prospectively.

Q. How did Staff determine its recommended assessment rate?

A. The current assessment rate in 2007 is 24 percent, and this will decrease to 23.5 percent for 2008, which is when rates established in this proceeding are to be in effect. Staff concluded that since the Commission approved rates are expected to become effective in early 2008, and the Company's anticipated rate case interval is three years, as evidenced by the Company's proposed normalization period for rate case expense, the property tax assessment ratio that will be in effect for 2008 of 23.5 percent is appropriate.

In terms of determining the recommended assessment ratio, I also considered how Staff's recommendation in the current UNS Electric rate case compares with Staff's similar determination in the recent Southwest Gas and UNS Gas rate cases. This comparison is summarized in the following table:

Utility:	UNS Electric, Inc.	UNS Gas, Inc.	Southwest Gas Corp.
Docket:	E-04204A-06-0783	G-04204A-06-0463	G-01551A-04-0876
Test Year Ended:	June 30, 2006	December 31, 2005	August 31, 2004
New Rates Effective:	Early 2008	mid-2007	Order issued 2/23/06
Estimated Filing Interval:	3 years or less	3 years	3 to 4 years
Assessment Rate Used:	23.5	24 percent	24.5 percent
Corresponding Effective Year:	2008	2007	2006

In the Southwest Gas case, it appears that the utility, Staff and RUCO all ultimately agreed on the appropriateness of using a 24.5 percent assessment rate effective for 2006 in conjunction with the test year in that case ending August 31, 2004. The information shown above for UNS Gas reflects Staff and RUCO proposals, with which UNS Gas did not agree. I believe the appropriateness of using the known 23.5 percent assessment rate in the current UNS Electric rate case is supported by the comparison in the above table.

Q. What is Staff's recommended property tax expense adjustment?

A. As shown on Schedule C-10, Staff's recommended adjustment reduces UNS Electric's proposed property tax expense by $59,747.

C-11 Rate Case Expense

Q. Please discuss the allowance for rate case expense.

A. UNS Electric's filing requests an amount of $600,000 for rate case expense normalized over a three year period, for an annual allowance of $200,000 per year.

Q. Does the fact that this is the first rate case for UNS Electric justify a $600,000 rate case expense?

A. No. While the current case may be the first rate case for this utility operation <u>under its current ownership</u>, it isn't the first rate case for this utility. This electric utility had periodic, recurring rate cases under its prior ownership by Citizens Utilities. The transfer of ownership should not be an excuse for charging ratepayers for what appear to be excessive amounts of rate case cost.

Moreover, the current UNS Electric rate case is similar to and presents many of the same issues, such as revisions to a PGA/PPFAC mechanism, adjustments to operating expenses for incentive compensation and SERP, etc., that were recently addressed by the Commission in Docket No. G-01551A-04-0876, a rate case involving a large gas distribution utility in the state, Southwest Gas Corporation. Staff believes that the

Southwest Gas case provides a reasonable benchmark for what a reasonable allowance for rate case cost should be in the current UNS Electric rate case.

Q. What does Staff recommend for the allowance for rate case expense for UNS Electric in this proceeding?

A. Staff recommends an annual allowance of $88,333 per year, based on a total of $265,000 normalized over three years. The total amount of rate case expense requested by UNS Electric of $600,000 and the annual allowance of $200,000 per year over a three-year period appears to be excessive and would represent an unreasonable burden on ratepayers. The amount of $600,000 requested by UNS Electric is over 2.5 times as high as the amount of rate case expense allowed by the Commission in the Southwest Gas rate case, which was $235,000 in total, and which was normalized over a three-year period. Although Southwest Gas is a larger utility than UNS Electric, the current UNS Electric rate case has similarities to the Southwest Gas rate case in terms of both the scope of issues in the cases, and the majority of each application being sponsored by in-house or affiliated company staff. Staff Adjustment C-11 reduces the $200,000 annual amount that was requested in the Company's original filing for rate case expense by $111,667 to provide for an annual allowance of $88,333 per year.

C-12 Edison Electric Institute Dues

Q. Please explain Staff's proposed adjustment for Edison Electric Institute dues.

A. This adjustment is shown on Schedule C-12 and reduces test year expense by $8,470. It reflects the removal of 49.93 percent of EEI core dues and 100 percent of the EEI UARG dues.

Q. How does Staff's proposed adjustment for Edison Electric Institute dues compare with UNS Electric's proposed treatment of such dues?

A. As noted above, Staff's adjustment reflects the removal of 49.93 percent of EEI core dues and 100 percent of the EEI UARG dues. UNS Electric's filing reflected the removal of 20 percent of the EEI core dues (apparently only the direct lobbying portion), and none of the EEI UARG dues.

Q. How did you determine the portion of EEI core dues that should not be charged to ratepayers?

A. I obtained a classification by NARUC category for EEI Core Dues activities for the year ended December 31, 2005. This is shown on Schedule C-12, page 2. EEI Core Dues relating to the following activities should be excluded from rates:

- Legislative Advocacy
- Regulatory Advocacy
- Advertising
- Marketing
- Public Relations

The sum of EEI Core Dues activities for these NARUC categories totals 49.93 percent, as shown on Schedule C-12, page 2.

Q. What is the purpose of the NARUC-designated categorization of EEI expenditures?

A. The purpose of the NARUC-designated categorization of EEI expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities. Certain expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit. The NARUC-designated categories of EEI expenditures are thus intended to be helpful to state utility regulatory commissions.

Q. Was this same percentage for the EEI core dues disallowance recently used in any other electric utility rate cases?

A. Yes. The Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc., rate case, in Order No. 10 (6/15/07) adopted a similar adjustment to reflect the disallowance of 49.93 percent of EEI core dues. This 49.93 percent disallowance of EEI core dues corresponds to the above-identified activity categories.

Q. What is UARG?

A. UARG is the EEI Utility Air Regulatory Group, which EEI sometimes also refers to as the "Separately Funded Activity" ("SFA") for Environment. This group, like the other EEI separately funded activities (or "U-groups") advocates the electric utility industry's views before legislative, regulatory, and judicial bodies. Therefore, these costs should not be borne by ratepayers. I recommend disallowing $5,477 of UARG dues from the cost of service.

Q. Did UNS Electric provide information from EEI indicating the non-deductible percentage for UARG?

A. Yes. A letter from EEI dated July 26, 2006, states that 100 percent of such activities are non-deductible:

> "We have completed the calculation of EEI's actual expenditures relating to influencing legislation for calendar year 2005. A total of ... 100% of the assessment for the SFA for Environment were devoted to non-deductible activities."

EEI's letter refers to UARG as the SFA for Environment. EEI's invoices refer to the SFA-Environment by its traditional designation, UARG. Association activities such as lobbying and influencing legislation is considered a "non-deductible activity" for federal income tax purposes. Accordingly, 100 percent of the UARG dues related to "non-deductible activity" should be disallowed for ratemaking purposes.

C-13 Other Membership and Industry Association Dues

Q. Please explain Staff's proposed adjustment for Other Membership and Industry Association Dues.

A. This adjustment reduces test year expense by $ $6,482, as shown on Schedule C-13 to remove other discretionary membership and industry association dues which are not needed for the safe and reliable provision of electric utility service.

This adjustment includes the removal of the $1,750 for the Arizona-Mexico Commission identified in the Company's response to data request STF 3.55. The Company's response to Mr. Magruder's second set of data requests, MM DR 2.27, states that: "The $1,750 for the Arizona-Mexico Commission should have been removed from expenses included in the revenue requirement. This invoice was overlooked in error and will be adjusted out of test year expense."

Q. Do you have any other recommendations concerning UNS Electric's participation in industry associations that the Company seeks to charge to ratepayers?

A. Yes. With any future rate filing in which UNS Electric may seek rate recovery of industry association dues or trade associations, the Company should include a cost-benefit analysis, reflecting all benefits it deems it has received over the prior 24 month period from any trade organization for which it seeks membership cost recovery. Such cost-benefit analysis should quantify each utility-asserted benefit of membership, showing the tie between the organization's activities and the benefits which are directly provided to ratepayers.

C-14 Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-14. This adjustment increases income tax expense by the amount shown on Schedule C-14 and decreases the Company' achieved operating income by a similar amount.

C-15 Depreciation Rates Correction

Q. Please explain Staff adjustment C-15.

A. This adjustment reduces annualized depreciation expense by $63,105 to correct the Company's proposed depreciation rate for transportation equipment. The Company's response to data request STF 3.39 states that:

> "Foster Associates inadvertently failed to include a 10 percent net salvage rate for UNS Electric transportation equipment. The impact of this oversight would be a further reduction in 2006 annualized accruals of $143,297. It is the opinion of Foster Associates that the magnitude of the additional depreciation reduction does not warrant a refilling of the depreciation study."

The Company's response to data request STF 11.8 provided additional details on the impact of the depreciation rate correction.

Q. Do you agree with the Company's depreciation witness, Dr. Ronald White, that the magnitude of the additional depreciation reduction does not warrant a re-filing of the depreciation study?

A. Yes. I agree that the depreciation rate study sponsored by Dr. White does not need to be re-filed. However, the error correction should be reflected in the calculation of annualized depreciation expense. Additionally, the Commission should approve and UNS Electric should then use prospectively, the corrected depreciation rates that were provided in the response to data request STF 11.8 (as opposed to the uncorrected rates that were presented in Dr. White's exhibit).

Q What is the impact on depreciation expense?

A. As shown on Schedule C-15, page 1, the Company's proposed annualized depreciation expense (Account 403) is reduced by $64,872 and the amortization of utility plant acquisition adjustment (Account 406, which is a credit to expense) is reduced by $1,767, for a net reduction to operating expense of $63,105.

Q. What is shown on the other pages of Schedule C-15?

A. The other pages of Schedule C-15 show the calculation of this adjustment in detail. Schedule C-15, page 2, shows the following information:

- Section A shows the Depreciation Rates for Transportation Equipment (before correction) as applied to the Transportation Equipment plant balances by UNS Electric (from the UNS Electric workpapers). This produced total annualized depreciation on Transportation Equipment of $1,534,515.
- Section B shows the corrected Depreciation Rates for Transportation Equipment as applied to the Transportation Equipment plant balances. This produces total annualized depreciation on Transportation Equipment of $1,378,197.
- Section C shows the derivation of Staff's pro forma adjustment for Depreciation Expense in Account 403. The decrease to annualized Depreciation Expense on Transportation Equipment of $156,318 is multiplied by the O&M percentage of 41.5 percent to derive the decrease in Depreciation Expense charged to O&M of $64,872.

Schedule C-15, page 3 of 4, shows this same result (as a check) with references to detailed supporting information that is shown in Schedules C-15.1 and 15.2, respectively.

Schedule C-15, page 4 of 4, is similar to the presentation on Schedule C-15, page 2. Page 4 shows the derivation of the Staff adjustment for the Amortization of Acquisition Discount, Account 406, of $1,767.

Q. You mentioned that Schedule C-15 references Schedules C-15.1 and C-15.2. What is shown on those Schedules?

A. Schedule C-15.1 reproduces the Company's detailed calculation workpapers relating to the Company's depreciation annualization adjustment. Schedule C-15.2 presents the same information, in the same format, but with the corrected Depreciation Rates for Transportation Equipment. As noted above, the corrected Depreciation Rates for Transportation Equipment were provided by the Company in response to data request STF 11.8.

Q. Do you address other aspects of the new depreciation rates proposed by UNS Electric, not directly related to a Staff operating expense adjustment, in another section of your testimony?

A. Yes. In Section V of my testimony, I address other aspects of the new depreciation rates proposed by UNS Electric.

C-16 Emergency Bill Assistance Expense

Q. Please explain Staff Adjustment C-16.

A. This adjustment increases test year expense to be included in the base rate revenue requirement determination by $20,000 to provide for an increase requested by the Company for emergency bill assistance. UNS Electric had included this $20,000 in its request for increased funding for its low-income weatherization program. UNS Electric also requested that the low-income weatherization program be included in the Commission-approved Demand Side Management (DSM) programs. Staff agrees with increasing the Company's requested allowance for emergency bill assistance by the $20,000, but disagrees that this should be part of a DSM program or that this particular expense should be included in the separate DSM surcharge rate. Accordingly, Staff has reflected the $20,000 increase in emergency bill assistance as an increase to operating expenses, so this can be included in base rates, and has excluded this expense from DSM programs. As shown on Schedule C-16, this adjustment increases operating expense by $20,000. The testimony of Staff witness Julie McNeely-Kirwan contains further explanations of Staff's reasons for this treatment.

C-17 Markup Above Cost for Charges from Affiliate, Southwest Energy Services

Q. How is UNS Electric charged for services provided by the affiliated company, Southwest Energy Services?

A. As described in the Company's responses to data requests STF 3.70, STF 10.4, STF 10.5, STF 10.6 and STF 11.10, Southwest Energy Services ("SES") is an affiliated company that performs supplemental work force services to UNS Electric and other affiliates. SES provides meter reading services for UNS Electric. SES began reading UniSource Energy Service, Inc.'s electric meter reads in February 2005. As described in the response to data request STF 10.6,

> "When SES provides supplemental work force services to UNS Electric, TEP or other affiliates, SES charges a 10% mark-up on the base wages of the supplemental worker.
>
> In addition, SES charges the cost of employer's taxes, workers' compensation and benefits. For example, for a supplemental administrative assistant that is paid $12.00 per hour, SES would charge ($12.00 + $1.20 markup) per hour, plus employer's taxes, worker's compensation and benefits (cost)."

Staff data request STF 15.1 requested additional information in order to quantify an adjustment to remove the 10 percent markup in the charges from the affiliate, SES, from

UNS Electric's test year expenses. As of June 26, 2007, the response to STF 15.1 stated that: "UNS Electric is in the process of gathering information and will provide the response to this data request as soon as the compilation is available."

V. DEPRECIATION RATES

Q. Please discuss the new depreciation rates that UNS Electric has proposed.

A. The development of new depreciation rates is addressed in the testimony of UNS Electric witness Ronald White, who sponsors the Company's 2006 depreciation rate study. The table presented at page 10 of Dr. White's testimony summarizes the overall changes. The depreciation rates proposed by primary account are equivalent to a composite rate of 4.18 percent. This is a reduction of 0.35 percentage points in comparison to the current composite rate of 4.53 percent. On December 31, 2005, plant investment, the difference between the current and proposed new depreciation rates produces a decrease in annualized depreciation expense for the electric utility of $1,231,943. This is shown on Statement B, at numbered page 18 of Dr. White's Attachment REW-2.

As described in the Company's responses to data requests STF 3.39 and STF 11.8, an additional reduction in annualized depreciation expense at the new rates, computed on December 31, 2005 plant investment of $143,297 is necessary to correct an error in the depreciation study. As described in the response to data request STF 3.39, the error resulted from Foster Associates' inadvertent failure to include a 10 percent net salvage rate for UNS Electric transportation equipment. The results of correcting this error are summarized in the following table:

Summary of Proposed Depreciation Rates and Accrual Before and After Error Correction

Line	Description	12/31/2005 Plant Investment (A)	2006 Annualized Accrual Present (B)	Proposed (C)	Difference (D)
	Proposed Before Error Correction [a]:				
1	Total Utility	$ 347,839,970	$ 15,761,231	$ 14,529,288	$ (1,231,943)
2	Equivalent Composite Rate		4.53%	4.18%	
	Proposed After Correcting Error [b]:				
3	Total Utility	$ 347,839,970	$ 15,761,231	$ 14,385,991	$ (1,375,240)
4	Equivalent Composite Rate		4.53%	4.14%	
5	**Difference in total annual accrual due to error correction [b]**			$ (143,297)	$ (143,297)

Source:
[a] UNS Electric, Direct Testimony of Dr. Ronald White, Exhibit REW-2, pages 3 and 18.
[b] Responses to Data Requests STF 3.39 and 11.8

Q. Why is the Staff adjustment C-15, which you discussed above, different in amount from the $143,297 correction to UNS Electric's annual depreciation accrual identified in the responses to data requests STF 3.39 and STF 11.8 and summarized in the above table?

A. It is different because of three factors. First, the $143,297 was calculated using plant investment as of December 31, 2005, whereas Staff adjustment C-15 used the Company's June 30, 2006 adjusted plant balances. Second, the $143,297 reflects the impact on the annual depreciation accrual before considering that a portion of the depreciation on transportation equipment is capitalized and therefore is not charged to O&M expense. Staff adjustment C-15 reflects the expensed portion of depreciation on transportation equipment. Third and finally, Staff adjustment C-15 reflects a related impact of the depreciation rate correction on amortization of the acquisition adjustment discount, which is not reflected in the $143,297.

Q. Please briefly describe the information you reviewed concerning UNS Electric's proposed depreciation rates.

A. The information I reviewed included the Commission's rules regarding depreciation, testimony and exhibits from the prior rate case, UNS Electric's application and testimony in the current case, UNS Electric's responses to data requests of Staff and other parties, Excel files supporting UNS Electric witness Ronald White's derivation of UNS Electric's depreciation rates, information provided to me by Staff, and other publicly available information.

Q. What Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. A copy of these rules are presented, for ease of reference, in Attachment RCS-3. The current version of the rules appear to have been adopted effective April 9, 1992. This pre-dates the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" which has resulted in revisions for financial reporting purposes, among other things, of the presentation of cost of removal information. I discuss SFAS No. 143 in more detail subsequently in my testimony.

Q. Did UNS Electric file a new depreciation study in the current rate case?

A. Yes. Exhibit REW-2 attached to Dr. White's testimony is the 2006 Depreciation Rate Study for UNS Electric, Inc.

Q. Please discuss the Company's proposed depreciation rates and how they were derived.

A. The new depreciation rates proposed by UNS Electric are summarized in Company witness Dr. White's testimony and are shown in detail in his Exhibit REW-2. The

Company's proposed rates were developed using a depreciation system composed of the straight-line method, broad group procedure and remaining life technique.

Q. What impact do the new depreciation rates proposed by UNS Electric have?

A. As summarized on page 10 of Dr. White's testimony, based on December 31, 2005 plant investment, the new depreciation rates proposed by UNS Electric decrease depreciation expense by $1,231,943 (from $15,761,231 at present rates to $14,529,288 at the Company's proposed rates). As described above, after correcting for an error in the depreciation study that is discussed in the Company's responses to data requests STF 3.39 and STF 11.8, the revised annual accrual is $14,385,991, and the annualized decrease in the depreciation accrual from existing rates is $1,375,240.

On a composite basis[8], after reflecting the error correction described in the responses to data requests STF 3.39 and STF 11.8, the Company's proposed new rates produce an decrease of 0.39 percentage points, from the current composite rate of 4.53% to a composite at new rates of 4.14%.

Q. Before discussing specific issues associated with UNS Electric's proposed depreciation rates, could you please provide your understanding of some basic depreciation terminology?

A. Yes, of course.

Q. What is depreciation?

A. The Commission's rules at R14-2-102(A)(3) define "depreciation" as "an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life."

[8] UNS Electric does not apply its depreciation rates on a composite basis; this information is for comparative purposes only.

Q. What is net salvage?

A. The Commission's rules at R14-2-102(A)(5) define "net salvage" as "the salvage value of property less the cost of removal."

Q. What is "salvage value"?

A. The Commission's rules at R14-2-102(A)(5) define "salvage value" as:

> "the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts."

Q. What is the "cost of removal"?

A. The Commission's rules at R14-2-102(A)(5) define the "cost of removal" as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."

Q. What is depreciation expense?

A. Depreciation expense is a charge to operating expense to reflect the recovery of depreciable utility plant. Depreciation rates are applied to a utility's depreciable utility plant to determine the amount of depreciation expense. Public utility depreciation expense is typically straight-line over the service life which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant and equipment is in service. [9]

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[9] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which defines "service life" as "the period between the date an asset is first devoted to public service and the date of its retirement from service."

Q. What is depreciable utility plant?

A. Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Plant additions, retirements and balances are maintained by plant account. An annual addition is the original cost of plant added to the account during the year. A retirement is recorded in the plant account by removing the original cost of a prior addition when such plant is removed from service. The plant balance is what is left at the end of an accounting period after accounting for additions and retirements.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense, called an accrual, is calculated by applying a depreciation rate to plant balances.

Q. Is the depreciation accrual a cash expense?

A. No. Depreciation is considered a <u>non-cash</u> expense.

Q. Please explain the distinction between a cash and non-cash expense.

A. Depreciation expense is considered a non-cash accrual. This contrasts with payroll expense, for example, which involves the current outlay of cash. Depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and is simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service. The following accounting entries illustrate the difference:

		Amount
Account	Description	Dr. (Cr.)
403	Depreciation Expense	$ 1,000
108	Accumulated Depreciation	$ (1,000)
	To record depreciation	
various	Payroll Expense	$ 1,000
131	Cash	$ (1,000)
	To record payroll expense	

Q. What is the Accumulated Depreciation account?

A. Accumulated Depreciation, Account 108 in the USOA, is a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. From a regulatory perspective, Accumulated Depreciation can be considered a measure of the depreciation recovered from ratepayers. Commission Rule R14-2-102 defines "accumulated depreciation" as "the sum of the annual provision for depreciation from the time that the asset is first devoted to public service."

Q. How does depreciation expense impact a utility's revenue requirement?

A. Annual depreciation expense is a cost that is included in a public utility's revenue requirement. Because public utilities tend to be capital intensive, depreciation expense can be a significant component of the utility's revenue requirement.

Q. What is the objective of depreciation expense?

A. From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances. Additionally, many state regulatory commissions, including the ACC, have allowed utilities to recover through the commission-authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.

Q. **Please illustrate how depreciation rates are developed.**

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life and a $1 million plant investment, and the whole life method. Each year the 10% depreciation rate would be applied to plant in service to produce an annual depreciation expense and an entry to accumulated depreciation:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: 100% / 10 Years = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
1	$ 100,000	$ (100,000)
2	$ 100,000	$ (200,000)
3	$ 100,000	$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 1,000,000	

Q. **What happens at the end of an asset's life under this scenario?**

A. All things equal, at the end of 10 years, the plant balance will be 100% (or $1 million), and the accumulated depreciation balance will also be 100% (also $1 million). This equality is important to understanding issues relating to the cost of removal/negative net salvage.

Q. What is negative net salvage?

A. Negative net salvage is the difference between any salvage value and the cost of removal of the asset after completion of its service life. If the cost of removal exceeds the salvage amount, this produces negative net salvage. In this testimony I will use the terms negative net salvage and net cost of removal interchangeably. The ratemaking treatment of negative net salvage was raised by a Staff witness (Mr. Majoros) as a major issue affecting utility depreciation rates in a previous APS rate case, Docket No. E-01345A-03-0437. Negative net salvage can have a significant impact on a utility's depreciation rates and revenue requirement.

Q. What happens if estimated future negative net salvage is included in the calculation?

A. Assume a negative 55 percent (-55%) net salvage ratio. The above whole-life example with a 55% value for negative net salvage is as follows:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [100% - (-55%)] / 10 Years = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
1	$ 100,000	$ (100,000)	$ 55,000	$ (55,000)
2	$ 100,000	$ (200,000)	$ 55,000	$ (110,000)
3	$ 100,000	$ (300,000)	$ 55,000	$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 1,000,000		$ 550,000	

In this example, negative net salvage increases the resulting whole-life depreciation rate from 10% to 15.5%, i.e., by 55%. This increase results from the inclusion of estimated future net cost of removal, including estimated future inflation.

Q. Please explain the "FAS 143 Regulatory Liability" column in the above example.

A. Because the Company has no current legal obligation to pay the estimated future inflated cost of removal (negative net salvage) amounts (i.e., has no asset retirement obligation), the excess amounts recovered through depreciation rates are accumulated in a regulatory liability account for financial reporting purposes, pursuant to Statement of Financial Accounting Standards No. 143. (SFAS 143) I will explain certain provisions in SFAS 143 that require such treatment in more detail later in my testimony.

Q. Why does negative net salvage increase the depreciation rate?

A. It increases the depreciation rate because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 155%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset. In the above example, instead of recovering the original plant cost of $1 million, the depreciation rates would recover $1.55 million.

Q. What happens at the end of a plant asset's life under this scenario?

A. The plant balance will be 100% but the sum of the accumulated depreciation balance and the regulatory liability account will be 155%. Consequently, unlike the "zero net salvage scenario" shown above, when negative net salvage is included in a depreciation rate, there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset. Under these circumstances, equality will only be achieved if the Company actually spends additional money at the end of the asset's life.

Q. Is the Company required to pre-collect from ratepayers estimated future amounts of money that it might spend at the end of plant useful life?

A. Where there is no legal requirement to incur cost of removal, UNS Electric has no current legal liability to spend money for estimated future cost of removal, the Commission rules at R14-2-102(B)(3) require that: "The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systematic manner over the estimated service life of the plant." As discussed above, the Commission's rules define "net salvage" to include the cost of removal. Consequently, I conclude that the Commission's rules require cost of removal to be included in the utility's depreciation rates.

Q. If the Company does incur an obligation at the end of an asset's service life that requires spending money for removal, can the Company take the money out of accumulated depreciation?

A. No. Accumulated Depreciation is an unfunded account. Even though the Company collected money from ratepayers for future removal cost that had been included in past depreciation rates, it will have already spent that money on whatever it chose in the past: salaries, dividends, etc.

Q. Please explain the concept of remaining life depreciation.

A. The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather that the whole life of the asset.

Q. What happens when accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If the 10-year asset is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 30% of the original cost because the 10% depreciation rate would have been applied for three years (3 x 10% = 30%). The remaining life depreciation rate would then be 10%, calculated as follows:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: [100% - 30%] / [10 - 3 Years] = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
3		$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 700,000	

Under the example with the assumed 55% negative net salvage, and a 7-year remaining life, the results would be a 15.5% depreciation rate, as shown below:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [(100% - (-55%)) - (3 x 15.5%)] / [10 - 3 Years] = 15.5% Per Year
Depreciation Rate: [(108.5%)] / [7 Years] = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
3		$ (300,000)		$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 700,000		$ 385,000	

Q. Why would the whole-life depreciation rate in the example with negative net salvage and the remaining life depreciation rate in the negative net salvage example both be 15.5 percent?

A. In these examples, the remaining life depreciation rate and the whole-life depreciation rates are the same (15.5 percent) because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 55% net salvage ratio, exactly the right amount of depreciation has been charged and collected in the past.

Q. What would happen if either of these fundamental parameters were to change?

A. If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than the whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage. The difference between the actual amount recovered, as included in the book depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

Q. Since the last revision to the Commission's rules regarding the treatment of depreciation, has a significant accounting pronouncement been issued?

A. Yes. As noted above, it appears that the Commission's rules concerning the treatment of depreciation were last revised and became effective April 9, 1992. Since that date, generally accepted accounting principles ("GAAP"), specifically SFAS 143, highlight the amounts associated with estimated future cost of removal for which no current legal obligation exists and require that they be reported as Regulatory Liabilities for financial reporting purposes. A regulatory liability can be viewed as an amount owed to ratepayers.

Q. What is SFAS 143?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession. In June 2001, the FASB promulgated Statement of Financial Accounting Standards No. 143 (FAS 143). This pronouncement addresses the appropriate accounting for long-lived assets. It is effective for all fiscal years beginning after June 15, 2002. However, earlier application was encouraged. Pursuant to SFAS 143, all companies, both unregulated (e.g., Walmart) and regulated (e.g., UNS Electric) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove retired assets. For some plant and equipment, companies have a legal obligation to remove the asset at the end of the service life. These legal obligations for future removal are called asset retirement obligations ("AROs"). For other assets, no such obligation exists.

If a company does have an ARO, the fair value of the future retirement cost, which is determined using net present value techniques, is considered to be part of the original cost of the asset. That ARO is therefore capitalized (included in the original cost) and depreciated over the life of the asset. In essence, if a Company incurs a legal liability to spend money to remove an asset at the end of its life, that liability is part of the cost of the asset.

In contrast, if a company does <u>not</u> have such legal obligations, the future cost of removal will <u>not</u> be capitalized as part of the asset cost and will <u>not</u> be included in depreciation expense. Only the initial cost of the asset (which does not include estimated inflated future cost of removal for which no current liability exists), will be depreciated.

At the end of the asset's life, for assets without AROs, the accumulated depreciation account will equal the plant balance. In other words, under SFAS 143, there is symmetry between assets with and without AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

Q. How are AROs measured?

A. AROs are measured at their net present value, not their inflated future value.

Q How are AROs recorded for accounting purposes?

A. As stated above, AROs are capitalized as a cost of the related asset and simultaneously recorded as a liability for those companies with a legal obligation to remove a retired asset. To illustrate, assuming an ARO of $500, the $500 would be debited (i.e., added) to plant and simultaneously credited (i.e., added) to the regulatory liability account. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability, but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. What happens if a company does not have an asset retirement obligation pursuant to SFAS 143?

A. If a company does not have such obligations, the estimated future inflated cost of removal is not considered as a cost of the asset, and therefore it will not be included in the company's depreciation expense on its general purpose financial statements. SFAS 143, therefore, unbundles net salvage from depreciation rates. It does this in two ways: (1) by incorporating the net present value of an ARO in the cost of the asset, or (2) by excluding non-AROs from the depreciation rate calculations.

Q. What is the accounting impact of SFAS 143 for electric utilities?

A. Under GAAP, electric utilities are required to review all of their assets to determine if they have any AROs. If a utility has any AROs, they are capitalized. Paragraph B73 of SFAS 143 provides an exception for regulated utilities, which allows them to continue to incorporate net salvage factors ("non-legal AROs") in depreciation rates even if they do not have AROs. Utilities are also required to determine the amount of any prior cost of removal collections relating to non- AROs that is now included in their accumulated depreciation accounts, and reclassify these and any such future charges as a regulatory liability in their financial statements. In other words, even with the paragraph B73 exception, SFAS 143 provides transparency through reporting disclosure requirements.

Q. What is the impact of SFAS 143 on electric regulatory accounting?

A. FERC addressed SFAS 143 in Docket RM02-7-000 which resulted in Order No. 631. FERC Order 631 essentially adopts SFAS 143 and integrates it into the Uniform System of Accounts. Utilities are required to review their long -lived assets to determine if they have any AROs. Where utilities do not have AROs, any charges for such amounts must be separately identified. FERC Order 631 defines cost of removal allowances for which there is no legal asset retirement obligation, as "non-legal retirement obligations." Past and future "non- legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account. In Order 631, FERC maintains the transparency resulting from the "separation principle" for non-legal AROs that was established in paragraph B73 of SFAS 143. Paragraph 38 of Order 631 explains FERC's new requirements for non-legal AROs:

> "Instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation - Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals."

Q. Does FERC provide any additional insight as to the interpretation of these new rules?

A. Yes, at paragraph 39 of the order, FERC states:

> "Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of

current accruals for specific allowances collected in rates for non-legal retirement obligations."

Q. Does FERC make any policy calls concerning the appropriate treatment of the disposition of prior and future collections contained in these separate allowances?

A. No. As indicated at paragraph 64 of the Order, FERC declined to make such calls on a policy basis. Rather, FERC will resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis.

Q. Does FERC's Order require anything new or more with respect to its requirement for detailed depreciation studies?

A. No. At paragraph 65 of the Order, FERC states that:

"... this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates."

Additionally, footnote 45 states:

"When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate."

Thus, FERC recognizes distinctions between legal and non-legal AROs just as SFAS 143 recognizes those distinctions. On a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to include in rates.

Q. Has UNS Electric implemented SFAS 143?

A. Yes. The Company has implemented SFAS 143. Consistent with adopting this accounting principle for financial reporting purposes, UNS Electric reclassified prior year removal costs of approximately $1 million previously included in accumulated depreciation to the liability for asset retirements and removals in its Balance Sheets. As described on page 16 of the UNS Electric, Inc. Financial Statements for the Years Ended December 31, 2005 and 2004 (Exhibit KGK-1 to Ms. Kissinger's direct testimony): "UNS Electric had accrued $1 million at December 31, 2005 and $0.6 million at December 31, 2004, for the net cost of removal for interim retirements from its transmission, distribution and general plant. These amounts have been recorded as a regulatory liability."

When initially adopting SFAS 143, companies such as UNS Electric, reclassified for financial statement reporting purposes their accumulated cost of removal for which there is no current legal obligation for removal, from Accumulated Depreciation and reported this as a Regulatory Liability.

Q. Are the "costs of removal" that were reclassified as a regulatory liability for financial reporting purposes the result of UNS Electric's past depreciation rates?

A. Essentially, yes. Similar to most utilities, UNS Electric's past depreciation rates have included negative net salvage. This has resulted in UNS Electric pre-collecting from ratepayers estimated future costs of removal for non-legal AROs, which under SFAS 143, have been reclassified for financial reporting purposes as a regulatory liability.

Plant and equipment are retired from service at the end of their useful lives. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. The cost of removal net of the value received for the salvage constitutes net salvage. In more technical terms, gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. As discussed above, net salvage is the difference between gross salvage and cost of removal.

Q. Are net salvage ratios included in the Company's depreciation rate calculations?

A. Yes. Substantial negative net salvage ratios are included in several of UNS Electric's depreciation rates. The inclusion of negative future net salvage ratios in UNS Electric's proposed depreciation rates result in depreciation rates that are significantly higher in many instances than if no cost of removal had been included. As noted above, the inclusion of net salvage in depreciation rates appears to be consistent with past practices of the utility and Commission, and appears to be required by Commission rule R14-2-102(B)(3).

Q. Do UNS Electric's proposed depreciation rates include estimated future removal costs?

A. Yes. As noted above, UNS Electric's proposed depreciation rates include estimated future removal costs, including estimated future inflation. UNS Electric has done this by including negative net salvage ratios in the development of depreciation rates for many, but not all, of its depreciable plant assets.

Q. Where does UNS Electric develop its estimated future cost of removal that are included in its proposed depreciation rates?

A. These are developed in Mr. White's Attachment REW-2, on Statement D (average net salvage), Statement E (present and proposed parameters) of those attachments.

Q. Did you request UNS Electric to provide its actual cost of removal and net salvage information by plant account?

A. Yes. This was requested in data request STF-3.30 for years 2000 through 2005.

Q. Did UNS Electric provide that requested information plant account?

A. UNS Electric provided the requested information only for calendar year 2005, but not for the other years. In response to STF 3.30, the Company stated that: "Please see the response to STF 3.19. Neither Foster Associates nor UNS Electric has actual cost of removal and net salvage information for calendar years other than 2005."

Q. Have you made a comparison of how much UNS Electric's proposed depreciation rates would collect annually for estimated future cost of removal with the Company's recent actual cost of removal?

A. No. During the course of my analysis, I started to make such a comparison, but concluded that it was not necessary for purposes of this case because the Commission's rules at R14-2-102 require net salvage to be included in the development of the utility's depreciation rates. Since I am not recommending an adjustment to reflect an alternative treatment of cost of removal in this case, the comparative calculation related to quantifying such an adjustment was not pursued as it would have been if an adjustment to the Company's approach was being recommended.

Q. Has UNS Electric's approach to including net salvage in depreciation rates been widely used in the utility industry?

A. Yes. Many regulated utilities have used this approach. It is even addressed in the NARUC's 1996 Public Utilities Depreciation Practices Manual as a recommended approach. On the other hand, the same NARUC Manual at page 157 also states:

> "Some commissions have abandoned the above procedure [gross salvage and cost of removal reflected in depreciation rates] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred."

Q. In your opinion, is there a reasonable alternative to the approach used by UNS Electric?

A. Yes. Instead of incorporating estimated future cost of removal along with estimated future inflation into depreciation rates, providing a normalized level of removal cost as a current-period expense is a reasonable alternative for ratemaking purposes, in my opinion.

Q. Does the NARUC Manual indicate that some utility commissions are using this alternative approach?

A. Yes. The NARUC Manual at page 158 states that:

> It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly

become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current period accounting for gross salvage and, particularly, cost of removal.

Q. Could UNS Electric's approach result in accumulated depreciation exceeding the original cost of plant in service?

A. Yes. One of the mechanical problems with UNS Electric's approach is that it can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rates proposed by UNS Electric for distribution plant include estimated future cost of removal, and therefore produce higher depreciation rates than are necessary to fully depreciate the original cost of the plant. Therefore, at the end of its life, the accumulated depreciation account exceeds the plant account balance. Referring back to the hypothetical illustration that I presented earlier, with a 55% negative net salvage assumption, at the end of the 10-year assumed useful life, the utility has recorded $1.55 million in depreciation on a depreciable asset of $1 million. During the plant's depreciable life, the utility had no asset retirement obligation, but it would have collected an extra $550,000.

Q. How should the allowance for cost of removal be calculated?

A. Because the Commission's rules at R14-2-102 in their current form clearly require the inclusion of net salvage in the development of the utility's depreciation rates, and this is what UNS Electric has done, I am not in this proceeding recommending an alternative. Were it not for those rules, I believe there is substantial merit in the alternative recommended by the witness for Staff in the prior APS rate case cited above, which would provide for a normalized allowance for cost of removal based on the average of the most recent five years worth of actual net salvage activity. Essentially, the cost of removal is treated just as any other normalized operating expense.

Q. Are you aware of whether other regulatory commissions use that alternative approach for utility recovery of cost of removal?

A. Yes. A five-year average net salvage allowance approach has been used for many years by the Pennsylvania Public Utility Commission. In recent years, some other state regulatory commissions have used similar approaches that exclude estimated future cost of removal from the development of depreciation rates, and provide an allowance for the cost of removal based on an average of a utility's actual incurred cost.

Q. What are the advantages of that approach?

A. The five-year rolling average for recovery of cost of removal provides a reasonable method for addressing this controversial aspect of depreciation. UNS Electric's proposed development of depreciation rates essentially treats estimated future costs of removal (including estimated future inflation) as a current period expense, even when there is no current legal obligation to incur such cost. In contrast with UNS Electric's approach, a normalized expense allowance approach better conforms with the generally accepted accounting principles articulated in SFAS 143 by not treating estimated inflated future removal costs as if they were a current obligation and a current expense. Additional advantages offered by the normalized expense allowance approach include that it is simple, straight-forward and easy to implement, provides an opportunity for the Company to recover a normalized allowance for cost of removal based on recent actual cost, and avoids charging current customers for estimated future inflation. However, the

Commission's rules at R14-2-102 in their present state would appear to preclude this alternative for purposes of this case.

Rule R14-2-102 is a rule of general applicability to electric utilities in the state of Arizona. Because I believe there is no compelling reason to treat cost of removal (where there is no current obligation to incur such cost) differently from other normalized operating expenses, I recommend that the Commission consider amending Rule R14-2-102 to allow treatment of cost of removal in the manner recommended by Staff's consultant in the prior APS rate case.

Q. Should the depreciation rates proposed by UNS Electric be adopted for use in this case, as corrected in the responses to data requests STF 3.39 and STF 11.8?

A. Yes. The depreciation rates proposed by UNS Electric presented in Dr. White's Attachment REW-2 should be adopted for use in this case, after reflecting the corrections described in the responses to data requests STF 3.39 and STF 11.8. The depreciation rates proposed by UNS Electric were developed in a manner that is generally consistent with the Commission's rules for depreciation rates. My review of the details provided in Dr. White's Attachment REW-2 and other information indicates that those new rates proposed by UNS Electric are consistent with industry accepted depreciation practices. As noted above in my testimony, the net change in percentage terms resulting from UNS Electric's proposed new depreciation rates in composite terms is fairly small, a decrease of 0.39 percentage points for UNS Electric plant.

Q. Do you have any other recommendations concerning the depreciation rates proposed by UNS Electric?

A. Yes. Each of the new depreciation rates proposed by UNS Electric should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

VI. CHANGES TO PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

Q. What revisions to its PPFAC has UNS Electric proposed that you are addressing?

A. I am addressing the revisions to the PPFAC described primarily in the direct testimony of UNS Electric witnesses Pignatelli at pages 8-14, and DeConcini at pages 15-21. As summarized by Mr. Pignatelli on page 9 of his direct testimony and Mr. DeConcini on pages 16-21, UNS Electric is requesting the following modifications to the PPFAC mechanism:

1. A clarification of the costs that can be included in the PPFAC. UNS Electric proposes that all costs included in FERC accounts 501, 547, 555 and 565 be included in the PPFAC.
2. UNS Electric also seeks to recover the cost of credit support associated with fuel and purchased power procurement and hedging through the PPFAC.
3. A new cost recovery mechanism to automatically adjust the PPFAC rate based on a 12-month rolling average cost of purchased power and fuel (including a "phase in" provision).
4. The recognition of carrying costs on the PPFAC bank balances at an interest rate equal to the LIBOR rate plus 1 percent.

5. A Bank Threshold of $10 million with an automatically instated surcharge or credit to return the balance over the next twelve months, accompanied by an informational filing from the Company detailing the calculation.

Q. Why is UNS Electric requesting these PPFAC revisions?

A. As described in the direct testimony of UNS Electric witnesses Pignatelli (page 10) and DeConcini (pages 1-2 and 15-21), the Company is requesting these changes due to the addition of new resources and contracts to replace the existing Power Supply Agreement ("PSA") with Pinnacle West Capital Corporation ("PWCC"). As described by Mr. DeConcini on page 2 of his direct testimony:

> "I have proposed a new PPFAC that also will become effective on the date the PWCC PSA expires. The current UNS Electric PPFAC rate is fixed and is tied to the PWCC PSA costs. When the PWCC PSA expires, UNS Electric will need a PPFAC that will accurately reflect UNS Electric's procurement of wholesale power and fuel. The proposed PPFAC would be based on the elements typically underlying recently approved PPFACs and would include a 12-month rolling average cost of power supply as the basis for retail pricing adjustments."

Q. Is UNS Electric also proposing rate design changes related to the shifting of power supply costs from the PPFAC to base rates?

A. Yes. UNS Electric witness Erdwurm's direct testimony at page 21 proposes to increase the base rate power supply to "slightly more than" 7 cents per kWh, to reflect the current base power supply rate of approximately 5.2 cents per kWh plus the approximately 1.8 cents per kWh currently recovered by UNS Electric from customers through the PPFAC. UNS Electric proposes to reduce the PPFAC rate to zero until June 2008 when the PWCC

PSA expires. The Company states that the new PPFAC it proposes would go into effect upon the expiration of the PWCC PSA.

Q. Are you addressing such rate design aspects of UNS Electric's PPFAC-related proposals in this testimony?

A. No. As provided for in the Commission's Scheduling Order, Staff will address such rate design aspects of the Company's PPFAC in the Staff rate design testimony to be filed on July 12, 2007.

Q. As guidance for your review of UNS Electric's proposed PPFAC changes, did you review material in any other recent proceedings involving Arizona electric utility adjustment mechanisms related to the recovery of fuel and purchased power costs?

A. Yes. I reviewed material filed by Staff in the recent Arizona Public Service Company rate case, Docket No. E-01345A-05-816, concerning fuel and purchased power recovery mechanisms, including the Staff's proposed Plan of Administration for a revised APS Power Supply Adjustment Mechanism ("PSA") that was filed with Staff witness John Antonuk's supplemental testimony in that docket, and subsequently underwent further revisions. In that case, Staff undertook a detailed review and made recommended revisions to the APS PSA. There are clearly differences between APS and UNS Electric, including: APS is a much larger utility, APS owns substantial generating resources, including steam, nuclear and other production, and APS makes off-system sales. In contrast, historically UNS Electric has not owned large generating resources, but has purchased most of its power needs from others, such as under the current power supply agreement that UNS Electric has with PWCC. Despite such differences, I believe that the Staff evaluation of the APS PSA in that case and the related Staff recommendations and Commission determinations relating to the APS PSA can provide helpful guidance in reviewing the UNS Electric PPFAC in the current case. I will be referring to the latest available written iteration of the Plan of Administration that Staff developed for the APS PSA in my testimony and have attached a copy of it in Attachment RCS-4. I should note that this version of the Plan of Administration does not yet reflect the Commission's determinations in Docket No. E-01345A-05-0816 concerning the 90/10 sharing or the 4 mil per kWh annual cap, which I understand the Commission has retained in the APS PSA that was recently approved.

Q. Please describe the primary features of the current power supply agreement that UNS Electric has with PWCC.

A. UNS Electric currently has a full-requirements power supply agreement with PWCC ("PWCC PSA") that began on June 1, 2001 and expires on May 31, 2008. The PWCC PSA provides all energy and ancillary services to serve UNS Electric's entire load requirements at a fixed price per MWh.

Q. How will UNS Electric's power procurement change upon expiration of the PWCC PSA?

A. UNS Electric states in its direct testimony that it has developed a Procurement Plan which provides for a mix of market power purchases, resource acquisitions and contracts to provide the necessary capacity, energy, and reserves to reliably meet its load requirements after the PWCC PSA expires on May 31, 2008. Mr. DeConcini's direct testimony at pages 4-6 and his Confidential Exhibit MJD-2 provide a high level overview of the plan.

Q. Please discuss UNS Electric's current PPFAC.

A. The current UNS Electric PPFAC rate was set in Commission Decision No. 66028 (July 3, 2003), which approved the acquisition of the Citizens assets. The current PPFAC of

$0.01825/kWh was approved in Decision No. 66028 and reflects the fixed energy price under the PWCC PSA. The PPFAC provides an adjustment mechanism under which UNS Electric is allowed to pass through to customers purchased power and fuel cost increases and/or savings relative to a base power supply rate, via a surcharge or credit. The Company's current base power supply rate is $0.05194/kWh and was established in Decision No. 59951 (January 3, 1997).

The current PPFAC functions in the following manner. The Company's actual fuel and purchased power costs (excluding demand charges) are charged to a PPFAC Bank Balance. The sum of the base power supply rate plus any PPFAC rate are multiplied by energy consumption. The product of that multiplication, indicating the Company's recovery of fuel and purchased power costs, is subtracted from the PPFAC bank balance. When the PPFAC bank balance reaches a predetermined threshold, UNS Electric must make a filing with the Commission to propose a method to recover or return the bank balance. The current PPFAC cannot be changed without Commission approval.

Q. Does Staff agree with the Company's proposed new PPFAC?

A. No. While Staff agrees with some aspects of the Company's proposed changes to the current PPFAC, the changes proposed by UNS Electric, taken as a whole, would appear to result in inclusion of additional costs in the PPFAC, such as expenses for credit support, that have not been demonstrated to possess the characteristics of being material, volatile, and not within the Company's control. Additionally, by replacing provisions which currently require Commission review with automatic rate adjustment provisions, the Company's proposed new PPFAC could substantially reduce the level of regulatory scrutiny of purchased power and fuel costs. Such changes would seem to be particularly inappropriate at a time when the Company is transitioning from a full requirements contract with fixed pricing provisions to a new procurement environment after May 2008 when the current PPWC PSA expires. Especially in such an environment, Staff believes that there should be Commission review of changes in PPFAC rates before they become applicable.

Q. The Company has proposed that the PPFAC include all costs that are recorded in FERC accounts 501, 547, 555 and 565. Can you briefly summarize what expenses are recorded in each of these accounts?

A. Yes. I do note that Mr. DeConcini presents a very high level description of what costs are included in each of these accounts at page 17 of his direct testimony.

Account 501, Fuel (Steam), includes the cost of fuel used in the production of steam for the generation of electricity, including fuel handling.

Account 547, Fuel (Other Production), includes the cost of fuel (such as gas, oil, kerosene and gasoline) delivered to the station for other power generation.

Account 555, Purchased Power, includes the cost of electricity purchased for resale. As described in the FERC Uniform System of Accounts for Electric Utilities[10]:

> "A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc.,

[10] Code of Federal Regulations, Title 18, Volume 1, Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Revised as of April 1, 1999.

> Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.
>
> "B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract."

Account 565, Transmission of Electricity by Others, includes amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others.

Q. Has UNS Electric had fuel expense which it recorded in FERC accounts 501 or 547?

A. Staff understands that UNS Electric has incurred some fuel expense. However, a review of UNS Electric's operating expense information filed with its FERC Form 1 for calendar years, 2004 through 2006, indicates that the Company did not record any fuel expense in these accounts. Under the full-requirements contract with PWCC, the expense for purchased power has been recorded in Account 555.

Q. How do the FERC accounts that UNS Electric proposes to include in its PPFAC correspond with the FERC accounts that were included in Staff's proposed Plan of Administration for the APS PSA?

A. The FERC Accounts 501, 547, 555 and 565 that UNS Electric proposes to include in its PPFAC are basically the same accounts that Staff's proposed Plan of Administration includes for recovery by APS under the APS PSA. Page 15 of that Plan of Administration lists the accounts included for the APS PSA as these four FERC accounts, and, for APS, also Account 518, Nuclear Fuel. UNS Electric does not have any nuclear generation and does not record expense in Account 518.

Page 15 of the Staff proposed Plan of Administration for the APS PSA also specifies that: "Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA." I believe that allowing UNS Electric to recover prudent direct costs of contracts it uses for hedging system fuel and purchased power under its PPFAC would also be appropriate.

Q. Do you have any concerns regarding UNS Electric's proposal that the PPFAC should include all expenses in FERC accounts 501, 547, 555 and 565?

A. Yes. I have the following concerns regarding capacity costs that may be recorded in Accounts 555 and 565:

Account 555 can include capacity and demand charges. Including such capacity and demand charges in a PPFAC that is recovered on a per kWh basis presents a concern. Additionally, it is fairly common, in my experience, for PPFAC-type mechanisms to include purchased energy expenses, and to exclude capacity costs from the PPFAC but to provide for recovery of a normalized level of purchased capacity costs in the utility's base rates.

Account 565, Transmission of Electricity by Others, may also have a capacity or demand element, depending upon the particular contracts the utility enters into for transmission service.

Q. Why do you have a concern regarding the recovery of capacity costs that may be recorded in Accounts 555 and 565 in the PPFAC?

A. There are two primary bases for such concerns. First, UNS Electric has not demonstrated that capacity costs that may be recorded in Accounts 555 and 565 are volatile, material and beyond the control of utility management. Moreover, in situations where the electric utility owns the generating capacity or transmission, the traditional ratemaking treatment has been to include the cost of such capacity, as measured in a test year, in the determination of a utility's base rate revenue requirement. Allowing purchased capacity costs to be recovered in a PPFAC mechanism, where owned capacity is recovered in base rates, could result in management decision making favoring purchased capacity that would be recorded in Account 555, rather than owning capacity resources that would be recorded as plant assets and would be subject to rate base treatment.

Second, the PPFAC rate would apparently be applied to each customer's bill as a monthly per kWh charge that is the same for all customer classes. There are concerns that a uniform per-kWh charge for all customer classes might not be appropriate for capacity-related charges. Staff's rate design testimony to be filed on July 12, 2007 may present additional details concerning capacity cost recovery.

Q. Have you examined the historical volatility of UNS Electric's expenses in each of the four FERC accounts 501, 547, 555 and 565?

A. Yes. The following summary of annual expenses in each of these four accounts for 2004 through 2006 was compiled from FERC Form 1 information:

UNS Electric's Recorded Expenses in FERC Accounts
Proposed by the Company for Recovery Through a PPFAC Mechanism

Account	2004	2005	2006
501	$ -	$ -	$ -
547	$ -	$ -	$ -
555	$ 96,467,281	$ 100,300,283	$ 106,271,505
565	$ 6,388,498	$ 6,631,327	$ 7,026,755
TOTAL	$ 102,857,783	$ 106,933,615	$ 113,300,266

Source for expense account information: UNS Electric FERC Form 1

Annual Change ($)

555		$ 3,833,002	$ 5,971,222
565		$ 242,829	$ 395,428
TOTAL		$ 4,075,832	$ 6,366,651

Annual Change (%)

555		4.0%	6.0%
565		3.8%	6.0%
TOTAL		4.0%	6.0%

This information suggests that historically UNS Electric's purchased power expense in Account 555 and transmission of electricity by others in Account 565 are significant and material to the Company's operations, but have not been particularly volatile. However, the historical lack of volatility has most likely been enabled by the full requirements arrangement that UNS Electric has had under the PWCC PSA, which is scheduled to expire on May 31, 2008. From June 2008 forward, UNS Electric's purchased power costs are likely to be subject to a higher degree of fluctuation than they have historically been under the full requirements PWCC PSA.

Q. Please discuss UNS Electric's proposal for including the "cost of credit support associated with fuel and purchased power procurement and hedging" be included in the PPFAC.

A. Mr. DeConcini states at pages 17-18 of his direct testimony that: "Prepayments, cash escrow accounts, standby letters of credit and parental guarantees are all common forms of credit support" in the wholesale markets for fuel and purchased power, and that UNS Electric wants to include in the PPFAC "the costs associated with standby letters of credit, prepayments, cash escrow accounts and parent guarantees." UNS Electric proposes to charge to the PPFAC bank balance a cost for standby letters of credit at an annualized cost equal to 1.0 percent of the face amount issued. UNS Electric also proposes to charge the PPFAC bank balance for prepayments and cash escrow accounts at UNS Electric's cost of short term borrowing. Additionally, UNS Electric proposes to charge to the PPFAC bank balance for parental guarantees "at the same rate charged to UNS Electric for letters of credit issued under the UNS Electric credit facility."

Q. Do you agree with UNS Electric's proposal that "cost of credit support associated with fuel and purchased power procurement and hedging" be included in the PPFAC?

A. No. UNS Electric has not demonstrated that inclusion of such costs in a PPFAC mechanism is reasonable or appropriate, is a common practice in the electric utility industry, or that such costs would be appropriately recorded in one of the FERC accounts that the Company proposes as the basis for its PPFAC. Prepayments and the cash working capital requirement associated with fuel and purchased power are reflected in the determination of base rates as a component of the utility's rate base. The cost of financing rate base components is reflected in the determination of the utility's base rate revenue requirement. Staff recommends that UNS Electric's proposal for including the "cost of credit support associated with fuel and purchased power procurement and hedging" in the PPFAC be rejected.

Q. Please comment regarding the Company's proposal for basing the PPFAC on a 12-month rolling average cost of fuel and purchased power, including a "phase in" period.

A. This provision is not objectionable in itself; however, the Company's related proposal that the PPFAC rate changes are implemented **automatically** is not favored by Staff, especially at a time when UNS Electric's fuel and purchased power procurement would be undergoing significant changes, and may thus be deserving of a higher level of regulatory scrutiny. Also, the provision for changing PPFAC rates monthly is not favored because very frequent rate changes could increase customer confusion and cause negative customer reactions.

Q. What is your understanding of why UNS Electric has proposed the use of a rolling 12-month average?

A. At page 19 of his direct testimony, Mr. DeConcini states that the Company is requesting a 12-month rolling average because it provides a level of price smoothing to customers to help mitigate extreme price changes that may be only short term in nature. He also states that current Purchased Gas Adjuster Mechanisms for UNS Gas and Southwest Gas Corporation both have a 12-month rolling average auto-adjusting feature.

Q. What concerns were expressed by Staff concerning the use of a rolling average to set power supply adjustment rates in the recent APS rate case?

A. In the recent APS rate case, Staff recognized that the main advantage of a "rolling average" approach is that it would smooth out the cost discontinuities produced in very volatile energy markets, and is therefore responsive to the issue of managing volatility. However, when addressing the rolling average issue in the recent APS case, Staff had two concerns: (1) that such an approach could actually increase deferrals, and (2) that very frequent rate changes could increase customer confusion and cause negative customer reactions.[11]

Q. In the APS rate case, did Staff recommend an alternative to the use of a rolling average approach?

A. Yes. In the APS rate case, Staff recommended a Plan of Administration designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs, based on three components: (1) a forward component (based on forecast fuel and purchased power costs), (2) an historical component (which tracks the differences between actual and recovered costs), and (3) a transition component (which provides for recovery of balances arising under the provisions of the previous power supply recovery mechanism). The details of Staff's proposal in the APS case are more fully presented in the Plan of Administration, that I have presented for ease of reference in Attachment RCS-4.[12]

Q. Does Staff suggest that an alternative arrangement for a UNS Electric PPFAC that combined similar elements?

A. Yes. While the specific details would need to be tailored to UNS Electric's particular situation, Staff believes that a new PPFAC mechanism for UNS Electric that contains many of the same elements in the APS PSA Plan of Administration could be workable, and could provide benefits to UNS Electric and its ratepayers.

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[11] See, e.g., Docket No., E-01345A-05-0816, Supplemental Testimony of John Antonuk, at pages 23-24.
[12] As noted above in my testimony, this attachment is the most current iteration of the Plant of Administration for the APS PSA and does not yet reflect or incorporate the Commission's determinations in the APS rate case regarding the 90/10 sharing or the 4 mills per kWh annual bandwidth provisions.

Q. Do you agree with UNS Electric's proposal for recognition of carrying costs on the PPFAC bank balances?

A. I agree in general that providing for carrying costs on deferred PPFAC bank balances prospectively would be appropriate.

Q. What interest rate should be applied to the monthly PPFAC bank balance?

A. Staff recommends using an interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, applied each month to the previous month's balance. This is essentially the same recommendation for the carrying cost rate that Staff proposed in the APS PSA Plan of Administration.[13] The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the customer deposit rate.

Q. How does the carrying cost rate Staff recommends compare with UNS Electric's proposed interest rate for customer deposits?

A. As shown on Exhibit TJF-1 to Direct Testimony of Thomas J. Ferry, in the red-lined version of the Rules and Regulations, page 16 of 109, section 3, UNS Electric has proposed in its rate case to use the one-year Treasury constant maturities rate for customer deposits. This is the same interest rate that Staff recommends be applied to compute carrying charges on the monthly PPFAC bank balances.

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[13] See, e.g., Attachment RCS-__, pages 10, 11 and 13 of the Staff Proposed Plan of Administration.

Q. Please comment regarding the Company's proposal for increasing the PPFAC bank balance threshold to $10 million, with an automatically instated surcharge or credit to return the balance over the next twelve months.

A. The $10 million threshold is not objectionable, taken by itself. Mr. DeConcini states, on page 20, that the Company's proposed new threshold level of $10 million was calculated as 10 percent of test year fuel and purchased power costs and rounded to the nearest million dollars. Mr. DeConcini also indicates that this higher level will mitigate the need for frequent filings that might otherwise occur due to short-term changes in fuel and purchased power prices.

Staff does not object to the proposal by UNS Electric that a PPFAC bank balance exceeding $10 million should trigger a filing. However, Staff recommends that the filing be more than informational, that the period over which the bank balance is amortized into rates be left to the discretion of the Commission rather than be pre-mandated at 12 months, and that the surcharge not automatically become effective without Commission approval.

I also note that if a new PPFAC for UNS Electric is adopted that is similar to the APS PSA Plan of Administration, but tailored to UNS Electric's circumstances, this would provide for an appropriate filing and review process, and would avoid automatic rate changes occurring without Commission approval.

Q. What kinds of filing and reporting should be required for UNS Electric's new PPFAC mechanism?

A. Staff recommends that filing and reporting be required for a new UNS Electric PPFAC mechanism similar to those set forth in the APS PSA Plan of Administration, with such elements as the annual reporting period and specific information to be filed being appropriately tailored to fit UNS Electric's situation.

Q. What effective date does UNS Electric propose for a new PPFAC mechanism?

A. As stated on page 19 of Mr. DeConcini's direct testimony, UNS Electric proposes that the new PPFAC Mechanism begin June 1, 2008 upon the expiration of the PWCC PSA.

Q. Does Staff agree that a new PPFAC mechanism for UNS Electric should begin June 1, 2008?

A. Yes. While Staff does not agree with the specific new PPFAC mechanism that has been proposed by UNS Electric, and would prefer to see a new PPFAC mechanism for UNS Electric that more closely corresponds with the provisions of the APS PSA Plan of Administration, Staff does agree that it would be appropriate for a new PPFAC to begin June 1, 2008, to correspond with the expiration of the PWCC PSA.

Q. Has the Company proposed a phase-in period for its new PPFAC?

A. Yes. Mr. DeConcini's direct testimony at pages 19-20 describes the Company's proposed phase-in period, which would be applicable for the first six months after implementation of the mechanism beginning June 1, 2008.

Q. Does Staff agree with the Company's proposed phase-in?

A. No. Staff would prefer to have the new PPFAC for UNS Electric based on the three components (forward, historical and transition) that Staff recently recommended for the APS PSA Plan of Administration. The combination of the historical and transition components, which would need to be tailored to fit UNS Electric's particular circumstances, is believed to be sufficient to address issues related to transitioning from the Company's old PPFAC to a new PPFAC.

Q. What principal features should be considered in the design or modification of UNS Electric's fuel and purchased power adjustment mechanism?

A. The following features should be considered:

- There should be Commission review of proposed charges before they become applicable. The Company's current PPFAC already does this by requiring Commission approval of any PPFAC rate changes before they are implemented. The Company's proposed new PPFAC would eliminate this provision by providing for automatic rate changes to occur without Commission review of proposed charges before they become applicable.
- There should be a clear provision for the reconciliation of revenues and costs. The current PPFAC provides for a type of reconciliation in the PPFAC bank balance accounting, whereby fuel and purchased power expenses are matched with the base rate power supply and PPFAC revenues under which the Company recovers such costs.
- There should be an opportunity for an independent Commission review of prudence and reasonableness in all areas that drive the costs collected under the PPFAC. The content of these reviews and the issues they address should be subject to examination and comment by the affected stakeholders. The ultimate purpose of such reviews is to enable the Commission to make an informed determination of what, if any, costs resulted from ineffective or imprudent utility performance, and what, if any, adjustments should be made to future recoveries and over what periods of time.
- The PPFAC should provide a reliable mechanism for assuring reasonably prompt recovery of prudent and reasonable fuel and energy costs. Ideally, a well designed

PPFAC would avoid situations where delayed recovery of prudent and reasonable fuel and energy costs would have material financial consequences (e.g., through increased financing costs or restraints on access to financial resources). Put another way, the PPFAC should, by providing for reasonably prompt recovery of prudent and reasonable fuel and energy costs, help to maintain the utility's financial benchmarks that promote the ability to secure financing at costs favorable to customers.

Q. Are there any other considerations?

A. Yes. The Commission may want to include a provision designed to provide the utility with an incentive to procure fuel and purchased power at the lowest cost consistent with providing reliable electric service might be appropriate, although such provisions can be difficult to design in terms of providing the appropriate balance between facilitating recovery of prudently incurred costs and structuring the incentives.

Q. Please summarize your recommendations concerning the development of a new PPFAC mechanism for UNS Electric.

A. The new PPFAC proposed by UNS Electric contains objectionable features such as automatically adjusting rates without Commission approval and inclusion of costs that would more appropriately be addressed in base rates, as well as raising other concerns, and should therefore be rejected. A new PPFAC for UNS Electric should be developed along the lines of the APS PSA Plan of Administration Staff proposed for the Arizona Public Service Company in Docket Nos., E-01345A-05-0816 et al, after appropriate adjustments to fit UNS Electric's circumstances. The new PPFAC for UNS Electric should become effective June 1, 2008, upon expiration of the Company's all requirements power contract with PWCC.

VII. COMPANY'S PROPOSED RATEMAKING TREATMENT FOR A NEW PEAKING UNIT, BLACK MOUNTAIN GENERATING STATION

Q. What is the Black Mountain Generating Station ("BMGS")?

A. The BMGS is a 90 MW peaking facility under development at a site in Mohave County. BMGS consists of two LM 6000 combustion turbines. It is being developed by an affiliated company, UniSource Energy Development Company ("UEDC"). UNS Electric witness Kevin Larson states (at pages 2 and 4 of his direct testimony) that UEDC has negotiated a turnkey construction contract for the project totaling $46 million. UEDC is in the process of obtaining permits and making other arrangements to meet a projected operating date of May 2008. The Company estimates additional costs of permitting, site improvements, obtaining water supply, connecting to a gas pipeline, making substation improvements, providing project supervision and paying interest on borrowed funds of $14 million to $19 million. In total, UNS Electric estimates BMGS will cost $60 to $65 million.

Q. What ratemaking treatment is the Company requesting for BMGS?

A. UNS Electric requests that the Commission include the BMGS in its rate base effective as of June 1, 2008 as set forth in the testimony of Company witness Kevin Larson. Specifically, as explained on page 3 of Mr. Larson's direct testimony: "the Company is requesting a post-test year adjustment to rate base and a corresponding reclassification of rates effective June 1, 2008, or at a later date if commercial operation is delayed beyond June 1, 2008." The Company's proposed post-test year adjustment would add approximately $10 million to the non-fuel (base rate) revenue requirement, assuming a $60 million completion cost. As Mr. Larson further explains (on page 3 of his direct testimony): "On the effective date of this adjustment, UNS Electric would increase the average base delivery charge to customers by approximately 0.6 cents per kWh, and make a corresponding decrease of 0.6 cents per kWh to the base power supply rate." He states that, initially, this proposal will be "revenue neutral" to UNS Electric. Other features of the Company's proposed ratemaking treatment for BMGS include (per Mr. Larson's direct testimony, at page 4):

- If actual project costs exceed $60 million, UNS Electric will not seek rate base treatment of any cost difference until the Company's next rate case.
- Following the purchase of the project by UNS Electric and upon commercial operation of the facility, the Company would provide the Commission with a project completion report, detailing the cost of completion and the results of pre-commercial testing.
- Thirty days after such report is filed, or on June 1, 2008 if the project is completed prior to May 1, 2008, the Company would implement the rate reclassification described above.

Q. What has the Company said it would do if the Commission rejects its proposal for a post-test year adjustment to rate base?

A. At page 5 of his direct testimony, Mr. Larson states that UNS Electric could elect to enter into a purchased power agreement ("PPA") with its affiliate, UEDC. He states that the terms of the PPA would be subject to approval by the Commission and by FERC.

Q. What costs of BMGS have been incurred by UNS Electric?

A. It appears that only minimal, if any, costs have been incurred by UNS Electric in the test year. As of the end of the test year, it appears the Company had not incurred any cost for BMGS construction. The response to STF 11.2 states that none of the Company's end-of-test-year CWIP balance includes BMGS cost. Additionally, Staff's engineering report, which reported on the results of a site visit made in June 2007 among other things, revealed very little work has apparently been done at the plant site. It appears that costs related to BMGS construction are being recorded on the books of the affiliate, UEDC, rather than on UNS Electric's books.

Q. What concerns regarding regulatory lag has UNS Electric expressed related to BMGS?

A. Pages 7-8 of Mr. Larson's testimony expresses concern that the time lag between construction outlays, commercial operation and rate recognition of new generating facilities can be quite long if a post-test year adjustment to rate base is not allowed. He estimates that, since the units are not scheduled for completion until the second quarter of 2008, a test year ending June 30, 2008 would have to be used in order to get the full cost of these units into rates on an historical test year basis. He estimates that new rates reflecting the full cost of the peaking unit would not become effective until January 2010. He states that, "from a financial perspective, UNS Electric cannot wait until 2010 for rate recovery on a project of this size." Finally, he states that, "in light of this potential outcome, as well as the borrowing constraints faced by UNS Electric, a decision was made to develop the peaking facility project at UEDC."

Q. Does the Company's proposed treatment of BMGS appear to qualify as a post-test year adjustment in the current rate case?

A. No, it does not. There are several concerns with approving rate base treatment of BMGS in the current rate case, including the uncertainties relating to the plant. One of the primary deficiencies is that the plant is not expected to be in commercial operation until May or June of 2008. This is well beyond the end of the test year in the current UNS Electric rate case, and is several months beyond even the scheduled hearing. Additionally, there is uncertainty regarding the total cost of the plant. There is uncertainty regarding whether the ownership of the plant would be at the utility, UNS Electric, or with the affiliate, UEDC. There is uncertainty regarding whether it would be more economical for UNS Electric and its ratepayers for the utility to own the plant or to obtain power by some other means. Given the substantial uncertainties regarding BMGS, Staff believes it would be premature inappropriate to approve the Company's request for rate base inclusion.

Q. Although you believe that the BMGS does not qualify as a post-test year adjustment to rate base in the current rate case, is Staff sympathetic to the need for potentially providing some type of extraordinary ratemaking support for this plant, given the size of the project in relation to UNS Electric's existing rate base?

A. Yes. Staff understands that the cost of BMGS, if it is to be acquired by UNS Electric, would result in a significant increase in the Company's rate base. Staff is somewhat sympathetic to the Company's related concerns about providing a supportive regulatory treatment relating to the financing. Staff witness Alexander Igwe is addressing the Company's request for approval of issuing additional financing, and, as described in his testimony, Staff is supportive of that request, subject to certain safeguards.

Q. What does Staff recommend?

A. Staff recommends that the Commission deny the Company's requested rate base and ratemaking treatment of BMGS. Staff recommends that the Company apply for an accounting order requesting permission to defer costs related to BMGS from the date of the later of UNS Electric ownership or BMGS commercial operation until the unit is recognized in rate base in the Company's next rate case. Deferred accounting treatment would protect the Company's earnings until a new rate case could be filed and processed. This treatment would also enable an analysis of the various options once the total cost of BMGS is known.

Q. At page 4 of his direct testimony, Mr. Larson states that UNS Electric considered such an alternative, but it would not enable the Company to raise the capital necessary to purchase the facility, and would not provide the cash flow necessary to support an additional $60 million to $65 million of capital during the cost deferral period. Please respond.

A. A number of considerations lead Staff to conclude that an accounting order would be preferable to granting UNS Electric the post-test year rate base adjustment the Company has requested in this proceeding. There are presently too many uncertainties concerning BMGS to warrant granting the post test year rate base treatment requested by the Company. The uncertainties and other factors are such that granting the Company a post-test year rate base adjustment for this plant in the current rate case would be inappropriate.

First, the cost and commercial operation date of BMGS is not yet known with certainty.

Second, the Company's anticipated in-service date is well beyond the end of the June 30, 2006 test year being utilized in the current rate case.

Third, an accounting order granting deferral would protect the Company's earnings during the period before the plant received rate recognition.

Fourth, in terms of raising capital, it is unclear to Staff how UNS Electric would be unable to raise the capital to purchase the facility when an affiliated company, UEDC, could raise the capital to construct the plant and potentially finance it for use in a future purchase power agreement, for which key specifics, such as pricing and contract duration are currently unknown. As I have noted above, Staff witness Alexander Igwe has recommended approval of UNS Electric's requested financing.

Fifth, it not known whether having UNS Electric purchase a peaking unit such as BMGS is the most economical alternative to obtain power for the short, intermediate or long-term.

Sixth, in terms of the impact on cash flow, the Company's proposal is to have BMGS included in rate base by a "revenue neutral" rate reclassification that apparently would not result in any net rate adjustment. It is unclear how the Company's proposed "revenue neutral" rate reclassification would result in a substantial improvement in the Company's cash flow if it were to be implemented in a truly "revenue neutral" manner that did not result in a substantial net rate increase.

Q. Should the ratemaking treatment of BMGS and the Company's related concerns about cash flow and regulatory lag issues related to BMGS be addressed in the context of UNS Electric's next rate case?

A. Yes. Staff believes the ultimate rate base and ratemaking treatment of BMGS would best be determined in UNS Electric's next rate case.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Washington, Washington, D.C., Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016,	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)

Attachment RCS-2
Staff Accounting Schedules
Accompanying the Testimony of Ralph C. Smith

Schedule	Description	Pages
	Revenue Requirement Summary Schedules	
A	Calculation of Revenue Deficiency (Sufficiency)	1
A-1	Gross Revenue Conversion Factor	1
B	Adjusted Rate Base	1
B.1	Summary of Adjustments to Rate Base	1
C	Adjusted Net Operating Income	1
C.1	Summary of Net Operating Income Adjustments	3
D	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
B-1	Remove Construction Work in Progress	1
B-2	Adjust CWIP for Plant in Service by End of Test Year	1
B-3	Plant in Service Addition Subject to Reimbursement	1
B-4	Cash Working Capital - Lead/Lag Study	1
B-5	Accumulated Deferred Income Taxes	1
	Net Operating Income Adjustments	
C-1	Revenue Adjustment for CARES Discount	1
C-2	Remove Depreciation & Property Taxes for CWIP	1
C-3	Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year	1
C-4	Fleet Fuel Expense	2
C-5	Postage Expense	1
C-6	Normalize Injuries and Damages Expense	1
C-7	Incentive Compensation Expense	1
C-8	Supplemental Executive Retirement Plant (SERP) Expense	1
C-9	Stock Based Compensation Expense	1
C-10	Property Tax Expense	1
C-11	Rate Case Expense	1
C-12	Edison Electric Institute Dues	2
C-13	Other Membership and Industry Association Dues	1
C-14	Interest Synchronization	1
C-15	Depreciation Rates Correction	4
C-15.1	Depreciation Rates Correction - Details of Company's Pre-Correction Calculation	9
C-15.2	Depreciation Rates Correction - Details of Calculation Using Corrected Rates	9
C-16	Emergency Bill Assistance Expense	1
C-17	Markup Above Cost in Charges from Affiliate, Southwest Energy Services	N/A
	Total Pages	53

UNS Electric Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2006

Line No.	Description	Reference	UNS Proposed Original Cost (A)	UNS Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value (D)
1	Adjusted Rate Base	Sch. B	$ 140,991,324	$ 177,802,341	$ 130,471,537	$ 167,282,554
2	Rate of Return	Sch. D	9.89%	7.84%	8.99%	7.01%
3	Operating Income Required		$ 13,946,320	$ 13,946,320	$ 11,725,569	$ 11,726,507
4	Net Operating Income Available	Sch. C	$ 8,742,011	$ 8,742,011	$ 9,400,443	$ 9,400,443
5	Operating Income Excess/Deficiency		$ 5,204,309	$ 5,204,309	$ 2,325,126	$ 2,326,064
6	Gross Revenue Conversion Factor	Sch. A-1	1.6346	1.6346	1.634626	1.634626
7	Overall Revenue Requirement		$ 8,507,097	$ 8,507,097	$ 3,800,712	$ 3,802,245

Notes and Source
Cols. A & B taken from UNS Electric, Inc. filing, Schedule A-1

UNS Electric, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended June 30, 2006

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.36792%	0.36792%
3	Taxable Income as a Percent	99.63%	99.63208%
4	Less: Federal and State Income Taxes	38.46%	38.46%
5	Change in Net Operating Income	61.18%	61.17609%
6	Gross Revenue Conversion Factor	1.6346	1.634626

Notes and Source
Col.A: UNS Electric Inc. Filing, Schedule C-3
Col.B:

Components of Revenue Requirement Increase

	Amount	Percent
Net Income	$ 2,325,127	61.18%
Federal and State Income Taxes	$ 1,461,601	38.46%
Uncollectibles	$ 13,984	0.37%
Total Revenue Increase	$ 3,800,712	100.00%

UNS Electric, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended June 30, 2006

Line No.	Description	Original Cost: As Adjusted by UNS (A)	Original Cost: Staff Adjustments (B)	Original Cost: As Adjusted by Staff (C)	RCND: As Adjusted by UNS (D)	RCND: Staff Adjustments (E)	RCND: As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 390,513,651	$ (10,555,773)	$ 379,957,878	$ 612,326,062	$ (10,555,773)	$ 601,770,289
2	Less: Accumulated Depreciation	$ (159,524,693)	$ -	$ (159,524,693)	$ (257,585,628)	$ -	$ (257,585,628)
3	Net Utility Plant in Service	$ 230,988,958	$ (10,555,773)	$ 220,433,185	$ 354,740,434	$ (10,555,773)	$ 344,184,661
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ (93,273,341)	$ (150,061,415)	$ -	$ (150,061,415)
5	Less: Accum. Amort. - Citizens Acq. Discount	$ (11,224,066)	$ -	$ (11,224,066)	$ (18,123,969)	$ -	$ (18,123,969)
6	Net Citizens Acquisition Discount	$ (82,049,275)	$ -	$ (82,049,275)	$ (131,937,446)	$ -	$ (131,937,446)
7	Total Net Utility Plant	$ 148,939,683	$ (10,555,773)	$ 138,383,910	$ 222,802,988	$ (10,555,773)	$ 212,247,215
8	Customer Advances for Construction	$ (8,692,444)	$ -	$ (8,692,444)	$ (9,559,141)	$ -	$ (9,559,141)
							$ -
9	Customer Deposits	$ (3,778,419)	$ -	$ (3,778,419)	$ (3,778,419)	$ -	$ (3,778,419)
							$ -
10	Accumulated Deferred Income Taxes	$ 1,154,833	$ (161,555)	$ 993,278	$ 1,780,258	$ (161,555)	$ 1,618,703
11	Total Deductions	$ (11,316,030)	$ (161,555)	$ (11,477,585)	$ (11,557,302)	$ (161,555)	$ (11,718,857)
12	Allowance for Working Capital	$ 3,367,671	$ 197,541	$ 3,565,212	$ 3,367,671	$ 197,541	$ 3,565,212
							$ -
13	Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -
							$ -
14	Regulatory Liabilities	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Rate Base	$ 140,991,324	$ (10,519,787)	$ 130,471,537	$ 214,613,357	$ (10,519,787)	$ 204,093,570

Notes and Source
Cols. A and D: UNS Electric Inc. filing, Schedule B

Fair Value Calculation (Per Company)

Original Cost	$ 140,991,324	
RCND	$ 214,613,357	
Total	$ 355,604,681	
Average (Fair Value)	$ 177,802,341	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 130,471,537	
RCND	$ 204,093,570	
Total	$ 334,565,107	
Average (Fair Value)	$ 167,282,554	See Sch. A

UNS Electric, Inc.
Summary of Rate Base Adjustments

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule B.1

Line No.	Description	Staff Adjustments	CWIP	Rhode Homes Line Extensions	Customer Advances for Construction	Cash Working Capital	ADIT	N/A
			B-1	B-2	B-3	B-4	B-5	B-6
1	Gross Utility Plant in Service	$ (10,555,773)	$ (10,761,154)	$ 442,255	$ (236,874)			
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (10,555,773)	$ (10,761,154)	$ 442,255	$ (236,874)	$ -	$ -	$ -
4	Citizens Acquisition Discount	$ -						
5	Less: Accum. Amort. - Citizens Acq. Discount	$ -						
6	Net Citizens Acquisition Discount	$ -						
7	Total Net Utility Plant	$ (10,555,773)	$ (10,761,154)	$ 442,255	$ (236,874)	$ -	$ -	$ -
8	Customer Advances for Construction	$ -		$ -				
9	Customer Deposits	$ -						
10	Accumulated Deferred Income Taxes	$ (161,555)					$ (161,555)	
11	Total Deductions	$ (161,555)	$ -	$ -	$ -	$ -	$ (161,555)	$ -
12	Allowance for Working Capital	$ 197,541				$ 197,541		
13	Regulatory Assets	$ -						
14	Regulatory Liabilities	$ -						
15	Total Rate Base	$ (10,519,787)	$ (10,761,154)	$ 442,255	$ (236,874)	$ 197,541	$ (161,555)	$ -

UNS Electric, Inc.
Adjusted Net Operating Income

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C
Page 1 of 1

Line No.	Description	As Adjusted by UNS (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 156,651,860	$ 52,937	$ 156,704,797
2	Sales for Resale	$ 246,016	$ -	$ 246,016
3	Other Operating Revenues	$ 1,589,014	$ -	$ 1,589,014
4	Total Operating Revenues	$ 158,486,890	$ 52,937	$ 158,539,827
	Operating Expenses			
5	Purchased Power	$ 106,224,185	$ -	$ 106,224,185
6	Other O&M Expenses	$ 26,423,248	$ (527,396)	$ 25,895,852
7	Depreciation & Amortization	$ 11,812,574	$ (494,656)	$ 11,317,918
8	Taxes Other Than Income Taxes	$ 3,447,533	$ (292,679)	$ 3,154,854
9	Income Taxes	$ 1,837,339	$ 709,236	$ 2,546,575
10	Total Operating Expenses	$ 149,744,879	$ (605,495)	$ 149,139,384
11	Net Operating Income	$ 8,742,011	$ 658,432	$ 9,400,443

Notes and Source

Col. A: UNS Electric, Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Stafff Adjustments	CARES Discount	Remove Depreciation & Property Taxes for CWIP	Depreciation & Property Taxes for CWIP Found in Service	Fleet Fuel Expense	Postage Expense
			C-1	C-2	C-3	C-4	C-5
	Operating Revenues						
1	Electric Retail Revenues	$ 52,937	$ 52,937				
2	Sales for Resale	$ -					
3	Other Operating Revenues	$ -					
4	Total Operating Revenues	$ 52,937	$ 52,937	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power	$ -					
6	Other O&M Expenses	$ (527,396)				$ (70,391)	$ 17,503
7	Depreciation & Amortization	$ (494,656)		$ (449,816)	$ 18,265		
8	Taxes Other Than Income Taxes	$ (292,679)		$ (239,696)	$ 8,317		
9	PRE-TAX OPERATING EXPENSES	$ (1,314,731)	$ -	$ (689,512)	$ 26,582	$ (70,391)	$ 17,503
10	PRE-TAX OPERATING INCOME	$ 1,367,668	$ 52,937	$ 689,512	$ (26,582)	$ 70,391	$ (17,503)
11	Income Taxes	$ 709,236	$ 20,433	$ 266,138	$ (10,260)	$ 27,170	$ (6,756)
12	TOTAL OPERATING EXPENSES	$ (605,495)	$ 20,433	$ (423,374)	$ 16,322	$ (43,221)	$ 10,747
13	OPERATING INCOME	$ 658,432	$ 32,504	$ 423,374	$ (16,322)	$ 43,221	$ (10,747)

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Injuries and Damages Expense	Incentive Compensation Expense	SERP Expense	Stock Based Compensation Expense	Property Tax Expense	Rate Case Expense
		C-6	C-7	C-8	C-9	C-10	C-11
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power						
6	Other O&M Expenses	$ (159,063)	$ (42,448)	$ (83,506)	$ (82,873)		$ (111,667)
7	Depreciation & Amortization						
8	Taxes Other Than Income Taxes		$ (1,553)			$ (59,747)	
9	PRE-TAX OPERATING EXPENSES	$ (159,063)	$ (44,001)	$ (83,506)	$ (82,873)	$ (59,747)	$ (111,667)
10	PRE-TAX OPERATING INCOME	$ 159,063	$ 44,001	$ 83,506	$ 82,873	$ 59,747	$ 111,667
11	Income Taxes	$ 61,395	$ 16,984	$ 32,232	$ 31,987	$ 23,061	$ 43,101
12	TOTAL OPERATING EXPENSES	$ (97,668)	$ (27,017)	$ (51,274)	$ (50,886)	$ (36,686)	$ (68,566)
13	OPERATING INCOME	$ 97,668	$ 27,017	$ 51,274	$ 50,886	$ 36,686	$ 68,566

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2006

Line No.	Description	Edison Electric Institute Dues	Other Membership Dues	Interest Synchro-nization	Depreciation Rates Correction	Emergency Bill Assistance	SES Markup Above Cost
		C-12	C-13	C-14	C-15	C-16	C-17
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Purchased Power						
6	Other O&M Expenses	$ (8,470)	$ (6,482)			$ 20,000	
7	Depreciation & Amortization				$ (63,105)		
8	Taxes Other Than Income Taxes						
9	PRE-TAX OPERATING EXPENSES	$ (8,470)	$ (6,482)	$ -	$ (63,105)	$ 20,000	$ -
10	PRE-TAX OPERATING INCOME	$ 8,470	$ 6,482	$ -	$ 63,105	$ (20,000)	$ -
11	Income Taxes	$ 3,269	$ 2,502	$ 181,343	$ 24,357	$ (7,720)	$ -
12	TOTAL OPERATING EXPENSES	$ (5,201)	$ (3,980)	$ 181,343	$ (38,748)	$ 12,280	$ -
13	OPERATING INCOME	$ 5,201	$ 3,980	$ (181,343)	$ 38,748	$ (12,280)	$ -

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per UNS Electric filing, Schedule C-3

UNS Electric, Inc.
Capital Structure & Cost Rates

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule D

Line No.	Capital Source	Capitalization Amount	Capitalization Percent	Cost Rate	Weighted Avg. Cost of Capital
	UNS - Proposed				
1	Short-Term Debt	$ 5,000	3.97%	6.36%	0.25%
2	Long-Term Debt	$ 59,486	47.18%	8.22%	3.88%
3	Common Stock Equity	$ 61,587	48.85%	11.79%	5.76%
4	Total Capital	$ 126,073	100.00%		9.89%
	ACC Staff - Proposed				
5	Short-Term Debt	$ 5,000	3.96%	6.36%	0.25%
6	Long-Term Debt	$ 59,545	47.21%	8.16%	3.85%
7	Common Stock Equity	$ 61,587	48.83%	10.000%	4.88%
8	Total Capital	$ 126,132	100.00%		8.99%
9	Difference				-0.90%
10	Weighted Cost of Debt				4.10%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base				
11	Short-Term Debt	$ 5,172,024	3.09%	6.36%	0.20%
12	Long-Term Debt	$ 61,593,629	36.82%	8.16%	3.00%
13	Common Stock Equity	$ 63,705,884	38.08%	10.000%	3.81%
	Capital financing OCRB	$ 130,471,538			
14	Appreciation above OCRB not recognized on utility's books	$ 36,811,017	22.01%	0% [a]	0.00%
15	Total capital supporting FVRB	$ 167,282,555	100.00%		7.0100%

Notes and Source

Lines 1-4 taken from UNS Electric Inc. filing, Schedule D-1

Lines 5-8: Staff witness David Parcell

Lines 11-15, Col.A:

Fair Value Rate Base	$ 167,282,554	Schedule A
Original Cost Rate Base	$ 130,471,537	Schedule A
Difference	$ 36,811,017	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

UNS Electric, Inc.
Remove Construction Work in Progress

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (10,761,154)	A & B

Notes and Source
A: UNS Electric Filing, Schedule B-2, page 2, line 1
B: Testimony of Staff witness Ralph Smith

UNS Electric, Inc.
Adjust CWIP for Plant in Service by End of Test Year

Test Year Ended June 30, 2006

Line No.	Description	Plant Account	Amount	Reference
1	Adjustment to Plant in Service for Rhode Homes Line Extensions	365	$ 442,255	A
2	Adjustment to Customer Advances for Construction			A
3	Net Rate Base Adjustment		$ 442,255	

Notes and Source

A: Staff memorandum concerning its Preliminary Field Assessment of Used and Useful Review for UNS Electric as it relates to the Rhode Homes overhead line extensions

Line 2: Letter of Agreement dated March 2, 2006 indicates the customer will pay to the Company a total Customer Advance of $360,117
The Company's response to data request STF 15.4(f) and (g) indicate that, as of June 30, 2006, UNS Electric had received Customer Advances totaling $360,117 for this project, and no additional Customer Advances for this project have been received subsequent to June 30, 2006.

UNS Electric, Inc.
Plant in Service Addition Subject to Reimbursement

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Adjustment to Contributions in Aid of Construction Decrease to Plant in Service	$ (236,874)	Note A

Notes and Source

A: Staff memorandum concerning its Preliminary Field Assessment of Used and Useful Review for UNS Electric as it relates to the Tubac Golf Resort Overhead to Underground Conversion

The Company's response to STF 15.4(d) states that: "this customer requested work was paid 100% by the customer as a Contribution in Aid of Construction."

UNS Electric, Inc.
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 6/30/06

Line No.	Description (A)	FERC	Per UNS Electric Pro Forma Test Year Amount (A)		Staff Adjustments (B)	Staff Adjusted (C)	Expense Lag Days (D)		Net Lag Days (RevLag - Col. D) (E)	Lead/Lag Factor (Col. E/365) (F)	Cash Working Capital Required (Col. F X Col.C) (G)
	Operating Expenses:										
	Non-Cash Expenses -										
1	Bad Debts Expense	904	$ 579,538	1a	-	579,538					$ -
2	Depreciation	403/404	15,594,232	1.2a	(494,656)	15,099,576					-
3	Amortization	406	(3,781,658)	1.2b	-	(3,781,658)					-
4	Deferred Income Taxes		494,521	1.3a		494,521					-
	Other Operating Expenses -										
5	Salaries and Wages (UNSG Direct Employees)	Multi	4,571,466	2.2a		4,571,466	23.33	D.	12.26	0.0336	153,601
6	Incentive Pay (UNSE Direct Employees)	Multi	98,247	3a	(17,962)	80,285	267.00	D.	(231.41)	(0.6340)	(50,901)
7	Purchased Power		106,021,950	1b		106,021,950	33.79	E.	1.80	0.0049	519,508
8	Transmission Other		7,009,878	1c		7,009,878	40.67	F.	(5.08)	(0.0139)	(97,437)
9	Meter Reading		730,556	1d		730,556	33.67	G.	1.92	0.0053	3,872
10	Customer Records & Collection Expenses (excluding alloc.)	903	2,982,604	1e-4b	-	2,982,604	34.94	H.	0.65	0.0018	5,369
11	Office Supplies and Expenses	921	535,854	1.1a		535,854	50.89	I.	(15.30)	(0.0419)	(22,452)
12	Injuries and Damages	925	512,417	1.1b	(159,063)	353,354	70.52	J.	(34.93)	(0.0957)	(33,816)
13	Pension & Benefits	926	1,172,133	1.1c	-	1,172,133	51.37	K	(15.78)	(0.0432)	(50,636)
14	Support Services (Direct Labor, Burdens, System Allocation)		5,631,155	4a	(190,865)	5,440,290	44.77	L.	(9.18)	(0.0252)	(137,095)
15	Property Taxes	408	3,096,371	1.3b	(291,126)	2,805,245	213.00	M.	(177.41)	(0.4861)	(1,363,630)
16	Payroll Taxes	408	348,088	1.3c	(1,553)	346,535	19.87	M.	15.72	0.0431	14,936
17	Current Income Taxes		1,342,818	1.3d		3,513,655	41.42	M.	(5.83)	(0.0160)	(56,218)
18	Interest on Customer Deposits	431	217,492	1.3e		217,492	182.50	Q.	(146.91)	(0.4025)	(87,541)
19	Other Operations and Maintenance	Multi	2,587,216	X	(179,506)	2,407,710	41.21	N.	(5.62)	(0.0154)	(37,079)
20	Total Operating Expenses		149,744,878		(1,334,731)	150,580,984					
	Other Cash Working Capital Elements:										
21	Interest on Long-Term Debt		5,819,157	8a	(469,824)	5,349,333	90.22	O.	(54.63)	(0.1497)	(800,795)
22	Revenue Taxes and Assessments	Calc	$ 13,983,561	P.	343,456	14,327,017	45.71	M.	(10.12)	(0.0277)	(396,858)
23	Total Cash Working Capital - Calculated										$ (2,437,172)
24	Total Cash Working Capital - Per UNS Gas Filing, Schedule B-5, page 3 of 3										(2,634,713)
25	Adjustment to Cash Working Capital										197,541

Notes and Source
UNS Electric filing, Schedule B-5, page 3 of 3
RUCO 1.10 2005 UNSG Lead-Lag Summary.xls
Revenue Lag, in days 35.59
Col.B: Staff workpapers for CWC calculation

Line	Line 17, Col.C, Current income taxes:	Amount	Source
26	Per UNS Electric, Current Income Taxes	$ 1,342,818	Col.A, line 14
27	Staff adjustments to Current Income Taxes	$ 709,236	Schedule C.1
28	Staff adjusted Current Income Taxes before Revenue Increase	$ 2,052,054	Schedule C
29	Income taxes for revenue increase	$ 1,461,601	Schedule A-1
30	Total current income taxes for CWC calculation	$ 3,513,655	

2,546,575	-	$ 2,052,054	=	$ 494,521
Total Income Taxes		Current Inc Taxes		Deferred Inc Taxes
Schedule C		Line 28		Col. A, Line 4

Line	Line 22, Revenue Based Taxes	Amount	Source
31	Revenue adjustments	$ 52,937	Schedule C
32	Staff recommended rate increase	$ 3,800,712	Schedule A, filtered through CWC macro
33	Revenue adjustments	$ 3,853,649	
34	Revenue based taxes	0.0891249	B-4 W/P 2
35	Adjustment to revenue based taxes	$ 343,456	

UNS Electric, Inc.
Accumulated Deferred Income Taxes

Test Year Ended June 30, 2006

Line No.	Description	Account	Amount	Reference
1	SERP	190	$ (97,217)	A
2	Stock Based Compensation	190	$ (64,338)	A
3	Total Adjustment to ADIT		$ (161,555)	

Notes and Source

A: Staff has removed SERP and Restricted Stock from operating expenses and allocated incentive compensation expense 50/50 to shareholders and ratepayers. This adjustment coordinates the corresponding ADIT amounts with those recommendations.

Line No.	Account and Description	Per Books (1)	UNS Electric Adjustment (2)	UNS Electric Adjusted		Staff Adjustment
	Account 190					
4	SERP	$ 99,736	$ (2,519)	$ 97,217	a	$ (97,217)
5	Restricted Stock	$ 28,728	$ (1,970)	$ 26,758	b	$ (26,758)
6	Dividend Equivalents	$ 37,661	$ (1,844)	$ 35,817	c	$ (35,817)
7	Stock Options	$ -	$ 1,763	$ 1,763	d	$ (1,763)
8	Stock Based Compensation related ADIT	$ 66,389	$ (2,051)	$ 64,338		$ (64,338)

(1) Response to STF 3.60
(2) UNS Electric ADIT workpapers
a: UNS Electric workpaper "Pro Forma ADIT - Account 190" "SERP 12G"
b: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Restricted Stock 12F"
c: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Dividend Equivalents 12C"
d: UNS Electric workpaper "Pro Forma ADIT - Account 190" "Stock Options 12H"

UNS Electric, Inc.
Revenue Adjustment for CARES Discount

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Remove Company Revenue Adjustment for Company's Proposed Revisions to CARES Discounts	$ 52,937	A&B

Notes and Source
A: UNS Electric Filing, Schedule C-2, page 1, line 1
B: Testimony of Staff witness Julie McNeely-Kirwan

UNS Electric, Inc.
Remove Depreciation & Property Taxes for CWIP

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-2

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (449,816)	A
2	CWIP Related Property Tax Expense	408	$ (239,696)	A
3	Total Adjustments		$ (689,512)	

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 4, lines 7 and 8

UNS Electric, Inc.
Depreciation & Property Taxes for CWIP Found to be In-Service in the Test Year

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-3
Page 1 of 1

Line No.	Description	Account	Amount	Reference
1	Rhode Homes Related Depreciation Expense	403	$ 18,265	A
2	Rhode Homes Related Property Tax Expense	408	$ 8,317	B
3	Total Adjustments		$ 26,582	

A: Depreciation Rate taken from Attachment REW-2, Statement A, from Dr. White's testimony

Line No.	Description	Plant Account	Amount	Depreciation Rate	Depreciation Expense
4	Rhode Homes Overhead Line Extensions (see Sch. B-2)	365	$ 442,255	4.13%	$ 18,265

B: **Calculation of Property Tax Expense**

Line No.	Description	Amount	
5	Rhode Homes Overhead Line Extensions	$ 442,255	
6	Less: Accumulated Depreciation	$ (18,265)	
7	Subtotal	$ 423,990	
8	Assessment Ratio	23.5%	
9	Taxable Value	$ 99,638	
10	Mohave Property Tax Rate	8.3471%	per Company's Property Tax adjustment workpaper
11	Property Tax Expense	$ 8,317	

UNS Electric, Inc.
Fleet Fuel Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-4

Line No.	Description		Amount	Reference
1	UNS Electric Adjustment to Fleet Fuel Expense	$	73,661	A
2	Staff Recommended Pro Forma Adjustment to Fleet Fuel Expense	$	3,270	B
3	Adjustment to Fleet Fuel Expense	$	(70,391)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 3, lines 5 and 6

B: Per Company's workpapers showing calculation of Fleet Fuel Expense adjustment (except where noted)

4	Average construction FTE from July 2005 to June 2006		109.2	
5	Average miles driven/contruction FTE (Total miles = 1,560,271)		14,293	
6	Construction FTE for July 2006		114.5	
7	Assumed 2006-2007 mileage		1,636,549	L5 x L6
8	Miles/gallon (1,560,271 / 204,180)		7.63	
9	Gallons purchased		214,504	L7 / L8
10	Weighted average price per gallon	$	2.69	Note C
11	Pro forma fuel expenditures	$	577,016	L.9 x L.10
12	Test year expenditures	$	573,746	
13	Staff Recommended pro forma adjustment to Fleet Fuel Expense	$	3,270	L11 - L12

C: **Amounts taken from the Company's response to STF 11.24**

		Gallons	Fuel Cost	Weighted Average Cost/Gal
14	Wright Express (September 2006 - May 2007)	51,891	$ 139,467	$ 2.69
15	Kingman Gascard (September 2006 - May 2007)	71,885	$ 192,615	$ 2.68
16	Parker Oil (February through May 2007)	7,775	$ 22,304	$ 2.87
17	Weighted Average	131,551	$ 354,386	$ 2.69

UNS Electric, Inc.
Adjustment to Fleet Fuel Expense (supplemental worksheet)
Allocation of Staff adjustment to FERC accounts

Docket No. E-04204A-06-0783
Schedule C-4

Test Year Ended June 30, 2006

Co	Acct	Expense Type	FERC Account	DR	CR	Net Amount	% of Total	O&M Adjustment	Staff Adjustment
33	55000	403	546	$7,634.11		$7,634.11	0.85%	$28	($600)
33	55000	403	548	$1,198.26		$1,198.26	0.13%	$4	($94)
33	55000	403	549	$188.36		$188.36	0.02%	$1	($15)
33	55000	403	551	$9,428.90		$9,428.90	1.05%	$34	($741)
33	55000	403	553	$17,592.83		$17,592.83	1.96%	$64	($1,383)
33	55000	403	554	$9,332.50		$9,332.50	1.04%	$34	($734)
33	55000	403	557	$2,550.60		$2,550.60	0.28%	$9	($200)
33	55000	403	562	$3,237.60		$3,237.60	0.36%	$12	($255)
33	55000	403	563	$472.61		$472.61	0.05%	$2	($37)
33	55000	403	566	$2,075.77		$2,075.77	0.23%	$8	($163)
33	55000	403	570	$7,633.80		$7,633.80	0.85%	$28	($600)
33	55000	403	571	$395.23		$395.23	0.04%	$1	($31)
33	55000	403	580	$8,414.78		$8,414.78	0.94%	$31	($661)
33	55000	403	581	$54,108.09		$54,108.09	6.04%	$198	($4,253)
33	55000	403	582	$4,099.30		$4,099.30	0.46%	$15	($322)
33	55000	403	583	$33,150.21		$33,150.21	3.70%	$121	($2,606)
33	55000	403	584	$65,053.92		$65,053.92	7.26%	$238	($5,114)
33	55000	403	585	$165.43		$165.43	0.02%	$1	($13)
33	55000	403	586	$98,161.79		$98,161.79	10.96%	$358	($7,716)
33	55000	403	587	$1,717.22		$1,717.22	0.19%	$6	($135)
33	55000	403	588	$43,342.83		$43,342.83	4.84%	$158	($3,407)
33	55000	403	590	$9,421.61		$9,421.61	1.05%	$34	($741)
33	55000	403	592	$53,782.89		$53,782.89	6.01%	$196	($4,228)
33	55000	403	593	$93,650.75		$93,650.75	10.46%	$342	($7,362)
33	55000	403	594	$18,195.04		$18,195.04	2.03%	$66	($1,430)
33	55000	403	595	$8,141.32		$8,141.32	0.91%	$30	($640)
33	55000	403	596	$8,089.99		$8,089.99	0.90%	$30	($636)
33	55000	403	598	$171.22		$171.22	0.02%	$1	($13)
33	55000	403	901	$24,434.41		$24,434.41	2.73%	$89	($1,921)
33	55000	403	902	$13,012.92		$13,012.92	1.45%	$48	($1,023)
33	55000	403	903	$132,933.49		$132,933.49	14.85%	$485	($10,450)
33	55000	403	905	$1,969.74		$1,969.74	0.22%	$7	($155)
33	55000	403	908	$7,737.47		$7,737.47	0.86%	$28	($608)
33	55000	403	909	$7,376.08		$7,376.08	0.82%	$27	($580)
33	55000	403	910	$181.63		$181.63	0.02%	$1	($14)
33	55000	403	920	$0.00		$0.00	0.00%	$0	$0
33	55000	403	921	$111,418.51		$111,418.51	12.44%	$407	($8,758)
33	55000	403	925	$165.65		$165.65	0.02%	$1	($13)
33	55000	403	930	$34,835.19		$34,835.19	3.89%	$127	($2,739)
				$895,472.05	$0.00	$895,472.05		$3,270	($70,391)
						Staff adjustment amount from page 1:		$3,270	$ (70,391)

UNS Electric, Inc.
Postage Expense

Docket No. E-04204A-06-0783
Schedule C-5
Page 1 of 1

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Annualized Postage Expense	$ 341,321	A
2	Recommended Staff Annualized Postage Expense	$ 358,824	B
3	Adjustment to Annualized Postage Expense	$ 17,503	L2 - L1

Notes and Source

A: Per Company workpaper used in calculating its Postage Expense adjustment

B:

4	UNS Electric Annualized Postage Expense	$ 341,321
5	Postage increase effective 5/14/07 (.41/.39)	1.05
6	Staff adjusted annualized Postage Expense	$ 358,824

UNS Electric, Inc.
Normalize Injuries and Damages Expense

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Test Year Injuries and Damages Expense	$ 562,403	A
2	Staff Recommended Normalized Injuries and Damages Expense	$ 403,340	B
3	Adjustment to Injuries and Damages Expense	$ (159,063)	L2 - L1

Notes and Source

A: Amount taken from UNS Electric's response to STF 3.101

B: Amounts taken from UNS Electric's response to STF 3.101

January through December 2004	$ 352,589
January through December 2005	$ 356,992
January through December 2006	$ 500,440
Total	$ 1,210,021
Normalized over three years	3
Staff Recommended Normalized Injuries and Damages Expense	$ 403,340

FERC Account 925

UNS Electric, Inc.
Incentive Compensation Expense

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Staff Adjustment to UES's Performance Enhancement Plan (PEP)	$ (17,962)	A
2	Staff Adjustment to UES's Other Incentive Comp	$ (24,486)	B
3	Total Adjustment to Incentive Compensation Expense	$ (42,448)	
4	Adjustment to Taxes Other Than Income	$ (1,553)	B

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
	Performance Enhancement Plan			
581	Distribution - Load Dispatching	$ 292	50%	$ 146
588	Distribution - Miscellaneous Expense	$ 3,428	50%	$ 1,714
593	Distribution - Maintenance of Overhead Lines	$ 3,612	50%	$ 1,806
901	Customer Accounting - Supervision	$ 5,374	50%	$ 2,687
903	Customer Records & Collection Expense	$ 585	50%	$ 293
909	Informational & Instructional Advertising Expense	$ 2,139	50%	$ 1,070
920	A&G Salaries	$ 20,491	50%	$ 10,246
		$ 35,921		$ 17,962
408	Taxes Other Than Income	$ 3,105	50%	$ 1,553

B: Per UNS Electric Inc.'s response to STF 3.83

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
920	Deferred Compensation Plan	$ 9,035	50%	$ 4,518
923	Officer's Long Term Incentive Plan	$ 39,935	50%	$ 19,968
		$ 48,970		$ 24,486

UNS Electric, Inc.
Supplemental Executive Retirement Plant (SERP) Expense

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Remove Supplemental Executive Retirement Plan Expense	$ (83,506)	A

Notes and Source

A: Per the Company's response to STF 3.83

FERC 923

UNS Electric, Inc.
Stock Based Compensation Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-9

Line No.	Description	Amount	Reference
1	Remove Stock Based Compensation Expense	$ (82,873)	Note A

Notes and Source

A: Per Company's response to STF 10.11

Stock Option Expense	$	62,904
Performance Share Expense	$	19,969
Total	$	82,873

UNS Electric, Inc.
Property Tax Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-10

Line No.	Description	Amount	Reference
1	UNS Electric Proposed Decrease to Property Tax Expense	$ (130,301)	A
2	Staff Proposed Decrease to Property Tax Expense	$ (190,048)	B
3	Adjustment to Property Tax Expense	$ (59,747)	L2 - L1

Notes and Source
A: UNS Electric Filing, Schedule C-2, page 5, line 8
B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

Line No.	Utility Plant in Service Taxes	Generation	Transmission	Distribution	General/ Intangible	Total
4	Total Net Plant in Service - Rate Base	$ 18,471,624	$ 15,073,774	$ 99,401,194	$ 16,474,253	$ 149,420,845
5	Less: Non-Taxable Licensed Transportation in Rate Base	$ -	$ -	$ -	$ (3,834,788)	$ (3,834,788)
6	Less: Land Cost & Rights of Way in Rate Base	$ (408,603)	$ (681,822)	$ (695,700)	$ (30,719)	$ (1,816,844)
7	Less: Environmental Property in Rate Base	$ -	$ -	$ (5,563,286)		$ (5,563,286)
8	Less: Non-Taxable WAPA Portion of N Havasu Sub			$ (4,674,822)		$ (4,674,822)
9	Less: CWIP in Rate Base	$ (777,167)	$ (1,234,041)	$ (7,840,042)	$ (951,066)	$ (10,802,316)
10	Less: Net Book Value of Generation	$ (17,285,854)				$ (17,285,854)
11	Plus: Full Cash Value of Generation	$ 7,943,440				$ 7,943,440
12	Plus: Land FCV per AZ Department of Revenue			$ 1,551,539		$ 1,551,539
13	Plus: Materials and Supplies in Rate Base			$ 5,650,559		$ 5,650,559
14	Plant in Service Full Cash Value	$ 7,943,440	$ 13,157,911	$ 87,829,442	$ 11,657,680	$ 120,588,473
15	Assessment Ratio	23.5%	23.5%	23.5%	23.5%	
16	Taxable Value	$ 1,866,708	$ 3,092,109	$ 20,639,919	$ 2,739,555	$ 28,338,291
17	Average Tax Rate	9.6858%	9.6858%	9.6858%	9.6858%	
18	Property Tax - Subtotal	$ 180,806	$ 299,495	$ 1,999,141	$ 265,348	$ 2,744,790
19	Environmental Property in Rate Base	$ -	$ -	$ 5,563,286	$ -	
20	Statutory Full Cash Value Adjustment	50%	50%	50%	50%	
21	Environmental Full Cash Value	$ -	$ -	$ 2,781,643	$ -	
22	Assessment Ratio	23.5%	23.5%	23.5%	23.5%	
23	Taxable Value	$ -	$ -	$ 653,686	$ -	
24	Average Tax Rate	9.6858%	9.6858%	9.6858%	9.6858%	
25	Property Tax - Subtotal	$ -	$ -	$ 63,315	$ -	$ 63,315
26	Total Property Taxes	$ 180,806	$ 299,495	$ 2,062,456	$ 265,348	$ 2,808,105
27	Less: Recorded Property Taxes Excluding Call Center	$ (101,364)	$ (395,121)	$ (2,266,077)	$ (222,391)	$ (2,984,953)
28	Property Tax Expense Adjustment (subtotal)	$ 79,442	$ (95,626)	$ (203,621)	$ 42,957	$ (176,848)
29	Less: Estimated Property Tax Related to PHFFU					$ (13,200) *
30	Property Tax Expense Adjustment					$ (190,048)

***Plant Held for Future Use**

	Transmission	Distribution	Total
Original Cost	$ 320,000	$ 120,000	$ 440,000
Estimated Property Tax Rate	3.0%	3.0%	
Estimated Property Tax Expense	$ 9,600	$ 3,600	$ 13,200

2008 Arizona Statutory Assessment Ratio 23.5%

FERC Account 408

UNS Electric, Inc.
Rate Case Expense

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	UNS Electric Rate Case Expense per Company Filing	$ 200,000	A
2	Staff Recommended Rate Case Expense	$ 88,333	B
3	Adjustment to Rate Case Expense	$ (111,667)	L2 - L1

Notes and Source

A: UNS Electric Filing, Schedule C-2, page 3, line 6

B:	Staff Recommended Rate Case Expense	$ 265,000	Note 1
	Normalized Over Three Years	3	
	Staff Recommended Normalized Rate Case Expense	$ 88,333	

(1) Reflects an escalation of approximately 4% over the allowance recommended by Staff in the recent UNS Gas rate case

UNS Electric, Inc.
Edison Electric Institute Dues

Test Year Ended June 30, 2006

Line No.	Description	Test Year Amount (A)	Company Adjustment (B)	Company Adjusted Amount (C)	Staff Adjustment (D)	Staff Adjusted (E)
1	Regular Dues	$ 10,000	$ (2,000)	$ 8,000	$ (2,993) a	$ 5,007
2	2005 UARG	$ 24,071	$ -	$ 24,071	$ (2,675) b	$ -
3	2006 UARG	$ 2,802	$ -	$ 2,802	$ (2,802)	$ -
4	Total Test Year EEI Dues	$ 36,873	$ (2,000)	$ 34,873	$ (8,470)	$ 5,007
5	Journal Entry to Correct 2005 UARG per G/L	$ (21,396)	$ -	$ (21,396)	$ -	$ -
6	Adjusted Test Year EEI Dues	$ 15,477	$ (2,000)	$ 13,477	$ (8,470)	$ 5,007

Notes and Source

Col. A: Amounts taken from the Company's response to STF 3.72

a: Staff adjustment for Regular Dues based on a disallowance percentage of 49.93% (see page 2)

	Staff Adjustment
Regular Dues	$ 10,000
Regular Dues disallowance percentage	49.93%
Staff adjustment to Regular Dues	$ 4,993
Less: Company adjustment	$ (2,000)
Remaining Staff adjustment to Regular Dues	$ 2,993

b: Allocation of TEP's portion of 2005 UARG in the amount of $24,071 booked in error. Corrected by Journal Entry 910.

TEP allocation of 2005 UARG	$ 24,071
Correcting JE910	$ (21,396)
UNS Electric allocation of 2005 UARG	$ 2,675

Col D: Per letter from Edison Electric Institute included in Company's workpapers for its EEI adjustment, 100% of environmental related separately funded activities are classified as "non-deductible" expenses

FERC 930

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues	Recommended Disallowance
Legislative Advocacy	20.38%	20.38%
Legislative Policy Research	6.02%	
Regulatory Advocacy	16.49%	16.49%
Regulatory Policy Research	13.99%	
Advertising	1.67%	1.67%
Marketing	3.68%	3.68%
Utility Operations and Engineering	11.31%	
Finance, Legal, Planning and Customer Service	18.75%	
Public Relations	7.71%	7.71%
Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

UNS Electric, Inc.
Other Membership and Industry Association Dues

Docket No. E-04204A-06-0783
Schedule C-13

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Arizona Utility Investors Association	$ 2,500	930
2	Alliance of Utility Shareholder Associations (AUSA)	$ 100	930
3	Golden Valley Chamber of Commerce	$ 70	930
4	Kingman Mohave Lions Club	$ 120	921/930
5	Kingman Rotary Club	$ 383	921/930
6	Kingman Route 66 Rotary Club	$ 508	921/930
7	Kingsmen	$ 125	930
8	Kiwanis Club of Havasu	$ 666	930
9	Mohave Museum of History & Arts	$ 200	930
10	Nogales-Santa Cruz Chamber of Commerce	$ 60	930
11	Arizona-Mexico Commission	$ 1,750	930.1
12	Total Membership Dues	$ 6,482	

Line No.	Description	Total From Above	Adjustment
13	Total Amount Recorded in Account 921	$ 568	$ (568)
14	Total Amount Recorded in Account 930	$ 5,914	$ (5,914)
15	Total	$ 6,482	$ (6,482)

Notes and Source

Amounts taken from the Company's response to STF 3.72

L.11: Also see responses to data requests STF 3.55 and MM DR 2.27:
"The $1,750 for the Arizona-Mexico Commission should have been removed from expenses included in the revenue requirement. This invoice was overlooked in error and will be adjusted out of test year expense."

UNS Electric, Inc.
Interest Synchronization

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-14

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	130,471,537	Schedule B
2	Weighted cost of debt		4.10%	Schedule D
3	Synchronized interest deduction	$	5,349,333	Line 1 x Line 2
4	Synchronized interest deduction per UNS Electric	$	5,819,157	Note A
5	Difference (decreased) increased interest deduction	$	(469,824)	Line 3 - Line 4
6	Combined federal and state income tax rates		38.598%	UNS Electric Sch. C-3
7	Increase (decrease) to income tax expense	$	181,343	

Notes and Source

A RUCO 1.10 2006 UNSE Lead-Lag Summary.xls
Also, UNS Electric filing, Schedule B-5, page 3 of 3, line 21

UNS Electric, Inc.
Depreciation Rates Correction

Test Year Ended June 30, 2006

Line No.	Description	Amount	Reference
1	Adjustment to Depreciation & Amortization Expense	$ (63,105)	A

Notes and Source

A: Per Company's workpapers used to calculate its depreciation expense adjustment (except where noted)

FERC	Description	UNS Electric Proforma Adj. to Depreciation Expense	Staff Proforma Adj. to Depreciation Expense	Staff Adjustment	Additional Reference
403	Depreciation Expense	$ 122,500	$ 57,628	$ (64,872)	Pages 2 & 3
404	Amortization of Utility Plant	$ 323,410	$ 323,410	$ -	Page 3
406	Amortization of Utility Plant Acquisition Adjustment	$ 137,076	$ 138,843	$ 1,767	Page 4
	Total	$ 582,986	$ 519,881	$ (63,105)	

Test Year Ended June 30, 2006

Depreciation Annualization Adjustment

Line No.	FERC Account	Description	Balance at 6/30/06	Adjustments	Adjusted Balance	Depreciation Rate	Annualized Depreciation	
		A. Rates Per Company Proforma Adjustment						
1	392	Transportation Equipment - Class 1	$ 366,331	$ 10,369	$ 376,700	12.75%	$ 48,029	
2	392	Transportation Equipment - Class 2	$ 1,151,599	$ 32,595	$ 1,184,194	16.99%	$ 201,195	
3	392	Transportation Equipment - Class 3	$ 1,185,238	$ 33,548	$ 1,218,786	20.21%	$ 246,317	
4	392	Transportation Equipment - Class 4	$ 5,641,612	$ 159,683	$ 5,801,295	13.47%	$ 781,434	
5	392	Transportation Equipment - Class 5	$ 1,995,626	$ 56,485	$ 2,052,111	12.55%	$ 257,540	
7		Total Annualized Transportation Equip.					$ 1,534,515	
		B. Rates Per Response to STF 11.8						
8	392	Transportation Equipment - Class 1	$ 366,331	$ 10,369	$ 376,700	11.48%	$ 43,245	
9	392	Transportation Equipment - Class 2	$ 1,151,599	$ 32,595	$ 1,184,194	15.29%	$ 181,063	
10	392	Transportation Equipment - Class 3	$ 1,185,238	$ 33,548	$ 1,218,786	18.69%	$ 227,791	
11	392	Transportation Equipment - Class 4	$ 5,641,612	$ 159,683	$ 5,801,295	11.97%	$ 694,415	
12	392	Transportation Equipment - Class 5	$ 1,995,626	$ 56,485	$ 2,052,111	11.29%	$ 231,683	
13		Total Annualized Transportation Equip.					$ 1,378,197	
		C. Staff Adjustment						
14		Staff Adjustment Before Capitalization					$ (156,318)	L13 - L7
15		O&M Portion of Vehicle Depreciation					41.5%	
16		Staff Adjustment to Depreciation Expense					$ (64,872)	L14 x L15

Notes and Source

Staff proforma adjustment for Depreciation & Amortization based on revised depreciation rates for FERC account 392 - Transportation Equipment, which reflected a 10% net salvage rate that was inadvertently omitted from the depreciation study as addressed in the responses to STF 3.39 and STF 11.8

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Test Year Ended June 30, 2006

Depreciation Annualization Adjustment

Line No.	Description	Account 403	Account 404	O&M Exp.	Total	
	UNS Electric Proforma Adjustment - Schedule 15.1, page 12					
1	Test Year Recorded	$ 14,308,205	$ 390,304	$ 332,503	$ 15,031,012	
2	Annualized Depreciation	$ 16,110,715	$ 713,714		$ 16,824,429	
3	Less: Depr on CWIP Removed	$ (449,816)			$ (449,816)	
4	Vehicle Depreciation Chgs CWIP	$ (1,534,515)		$ 636,824	$ (897,691)	
5	Adjusted Annualized Depreciation	$ 14,126,384	$ 713,714	$ 636,824	$ 15,476,922	
6	Adjustment Amount	$ (181,821)	$ 323,410	$ 304,321	$ 445,910	
	Staff Proforma Adjustment - Schedule 15.2, page 8	Account 403	Account 404	O&M Exp.	Total	
7	Test Year Recorded	$ 14,308,205	$ 390,304	$ 332,503	$ 15,031,012	
8	Annualized Depreciation	$ 15,954,397	$ 713,714		$ 16,668,111	
9	Less: Depr on CWIP Removed	$ (449,816)			$ (449,816)	
10	Vehicle Depreciation Chgs CWIP	$ (1,378,197)		571,952	$ (806,245)	
11	Adjusted Annualized Depreciation	$ 14,126,384	$ 713,714	$ 571,952	$ 15,412,050	
12	Adjustment Amount	$ (181,821)	$ 323,410	$ 239,449	$ 381,038	
13	Staff Adjustment				$ (64,872)	L12 - L6

UNS Electric, Inc.
Depreciation & Amortization Expense - Supplemental Worksheet

Test Year Ended June 30, 2006

Acquisition Discount Annualization Adjustment

Line No.	FERC Account	Description	Balance at 6/30/06	Adjustments	Adjusted Balance	Depreciation Rate	Annualized Depreciation	
		Rates Per Company Proforma Adjustment						
1	392	Transportation Equipment - Class 1	$ (51,192)	$ 39,563	$ (11,629)	12.75%	$ (1,483)	
2	392	Transportation Equipment - Class 2	$ (16,191)	$ 12,513	$ (3,678)	16.99%	$ (625)	
3	392	Transportation Equipment - Class 3	$ (92,982)	$ 71,860	$ (21,122)	20.21%	$ (4,269)	
4	392	Transportation Equipment - Class 4	$ (362,404)	$ 280,080	$ (82,324)	13.47%	$ (11,089)	
5	392	Transportation Equipment - Class 5	$ -	$ -	$ -	12.55%	$ -	
7		Total Annualized Amort-Acq Adj	$ (522,769)	$ 404,016	$ (118,753)		$ (17,466)	
		Rates Per Response to STF 11.8						
8	392	Transportation Equipment - Class 1	$ (51,192)	$ 39,563	$ (11,629)	11.48%	$ (1,335)	
9	392	Transportation Equipment - Class 2	$ (16,191)	$ 12,513	$ (3,678)	15.29%	$ (562)	
10	392	Transportation Equipment - Class 3	$ (92,982)	$ 71,860	$ (21,122)	18.69%	$ (3,948)	
11	392	Transportation Equipment - Class 4	$ (362,404)	$ 280,080	$ (82,324)	11.97%	$ (9,854)	
12	392	Transportation Equipment - Class 5	$ -	$ -	$ -	11.29%	$ -	
13		Total	$ (522,769)	$ 404,016	$ (118,753)		$ (15,699)	
14		Staff Adjustment					$ 1,767	L13 - L7

Proforma Adjustment to FERC Account 406

Line No.	Description	Per Company Adj. Workpaper	Staff Adjusted	Staff Adjustment
15	Intangible Plant	$ (181,550)	$ (181,550)	
16	Other Production Plant	$ (136,670)	$ (136,670)	
17	Transmission Plant	$ (400,629)	$ (400,629)	
18	Distribution Plant	$ (2,824,706)	$ (2,824,706)	
19	General Plant	$ (238,101)	$ (236,334)	
		$ (3,781,656)	$ (3,779,889)	
20	Test Year Amount per Books	$ (3,918,732)	$ (3,918,732)	
21	Adjustment - FERC 406	$ 137,076	$ 138,843	$ 1,767

Notes and Source

Staff proforma adjustment for Acquisition Discount Annualization Adjustment based on revised depreciation rates for FERC account 392 - Transportation Equipment, which reflected a 10% net salvage rate that was inadvertently omitted from the depreciation study as addressed in the responses to STF 3.39 and STF 11.8

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Detail by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 28, 2006
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
FERC 403 & 404			
303	Miscellaneous Intangible Plant	$320,122	
341	Structures & Improvements	$73	
342	Fuel Holders, Producers, & Accessories	$131	
343	Prime Movers	$1,740	
344	Generators	$132	
345	Accessory Electric Equipment	$317	
346	Misc. Power Plant Equipment	$79	
352	Structures & Improvements	$62	
353	Station Equipment	$4,437	
354	Towers & Fixtures	$182	
355	Poles & Fixtures	$6,279	
356	Overhead Conductors & Devices	$2,661	
359	Roads & Trails	$32	
361	Structures & Improvements	$1,087	
362	Station Equipment	$11,845	
364	Poles, Towers, & Fixtures	$27,668	
365	Overhead Conductors & Devices	$18,396	
366	Underground Conduit	$4,718	
367	Underground Conductors & Devices	$10,668	
368	Line Transformers	$19,806	
369	Services	$3,877	
370	Meters	$2,341	
373	Street Lights and Signal Systems	$1,321	
390	Structures & Improvements	$3,674	
391	Office Furniture & Equipment	$2,504	
392	Transportation Equipment		$351
393	Stores Equipment	$28	
394	Tools, Shop, & Garage Equipment	$616	
395	Laboratory Equipment	$322	
396	Power Operated Equipment	$357	
397	Communication Equipment	$726	
398	Miscellaneous Equipment	$57	
FERC 406			
303	Miscellaneous Intangible Plant		$10,140
341	Structures & Improvements	$72	
342	Fuel Holders, Producers, & Accessories	$255	
343	Prime Movers	$2,947	
344	Generators	$270	
345	Accessory Electric Equipment	$561	
346	Misc. Power Plant Equipment	$160	

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Detail by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 28, 2006
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
352	Structures & Improvements	$44	
353	Station Equipment	$6,038	
354	Towers & Fixtures	$357	
355	Poles & Fixtures	$6,439	
356	Overhead Conductors & Devices	$3,525	
359	Roads & Trails	$46	
361	Structures & Improvements	$1,748	
362	Station Equipment	$16,268	
364	Poles, Towers, & Fixtures	$33,522	
365	Overhead Conductors & Devices	$20,619	
366	Underground Conduit	$6,754	
367	Underground Conductors & Devices	$10,428	
368	Line Transformers	$18,524	
369	Services	$5,937	
370	Meters	$3,479	
373	Street Lights and Signal Systems	$1,908	
390	Structures & Improvements	$641	
391	Office Furniture & Equipment	$4,538	
393	Stores Equipment	$37	
394	Tools, Shop, & Garage Equipment	$908	
395	Laboratory Equipment	$305	
396	Power Operated Equipment	$201	
397	Communication Equipment	$641	
398	Miscellaneous Equipment	$42	
	ENTRY TOTAL	**$593,473**	**$10,491**

NET ENTRY **$582,981**

(rounding variance of $5 with unallocated amounts is ignored - immaterial)

Reason for Adjustment

To adjust test year recorded depreciation to reflect annualized depreciation based on ending plant balances and the depreciation rates resulting from Dr. White's study. This adjustment excludes the effects of depreciation on the level of CWIP requested for inclusion in rate base.

To adjust test year recorded amortization expense to reflect acquisition discount in Decision No. 66028 and the depreciation rates resulting from Dr. White's study.

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Summary by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 26, 2006
PREPARED BY:	E. Fowler
CHECKED BY:	C. Dabelstein
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
403	Depreciation Expense	$122,500	
404	Amortization of Utility Plant	$323,410	
406	Amortization of Utility Plant Acquisition Adjustments	$137,076	
	ENTRY TOTAL	**$582,986**	**$0**

Reason for Adjustment

To adjust test year recorded depreciation and amortization expense to reflect the final adjusted balances

UNS Electric, Inc.
Allocation of Depreciation & Amortization Pro Forma Adjustment to FERC Accounts
Test Year Ended June 30, 2006

Function	Plt Acct & Desc	403 %	403 $122,500	403 %	404 $323,410	Total 403 & 404 $445,910	406 %	406 $137,076	Total $582,986
Intangible	302-Franchises & Consents	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Intangible	303-Intangibles	0.00%	$0	98.98%	$320,122	$320,122	-7.40%	($10,140)	$309,983
	Total Intangible		$0		$320,122	$320,122		($10,140)	$309,983
Other Production	340-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Other Production	341-Struct & Imprv	0.06%	$73	0.00%	$0	$73	0.05%	$72	$146
Other Production	342-Fuel Holders and Accessories	0.11%	$131	0.00%	$0	$131	0.19%	$255	$386
Other Production	343-Prime Movers	1.42%	$1,740	0.00%	$0	$1,740	2.15%	$2,947	$4,686
Other Production	344-Generators	0.11%	$132	0.00%	$0	$132	0.20%	$270	$403
Other Production	345-Accessory Elec Eq	0.26%	$317	0.00%	$0	$317	0.41%	$561	$879
Other Production	346-Misc Pwr Plt Eq	0.06%	$79	0.00%	$0	$79	0.12%	$160	$239
	Total Other Production		$2,473		$0	$2,473		$4,266	$6,738
Transmission	350-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Transmission	352-Str & Impr	0.05%	$62	0.00%	$0	$62	0.03%	$44	$106
Transmission	353-Station Eq	3.62%	$4,437	0.00%	$0	$4,437	4.41%	$6,038	$10,475
Transmission	354-Towers & Fixtures	0.15%	$182	0.00%	$0	$182	0.26%	$357	$539
Transmission	355-Poles & Fixtures	5.13%	$6,279	0.00%	$0	$6,279	4.70%	$6,439	$12,718
Transmission	356-OH Conduct & Devices	2.17%	$2,661	0.00%	$0	$2,661	2.57%	$3,525	$6,186
Transmission	358-UG Conductors & Devices	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Transmission	359-Roads & Trails	0.03%	$32	0.00%	$0	$32	0.03%	$46	$78
	Total Transmission		$13,654		$0	$13,654		$16,449	$30,103
Distribution	360-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Distribution	361-Struct & Imprv	0.89%	$1,087	0.00%	$0	$1,087	1.28%	$1,748	$2,835
Distribution	362-Station Eq	9.67%	$11,845	0.00%	$0	$11,845	11.87%	$16,268	$28,113
Distribution	364-Poles, Towers & Fixtures	22.59%	$27,668	0.00%	$0	$27,668	24.46%	$33,522	$61,190
Distribution	365-OH Conduct & Devices	15.02%	$18,396	0.00%	$0	$18,396	15.04%	$20,619	$39,015
Distribution	366-UG Conduit	3.85%	$4,718	0.00%	$0	$4,718	4.93%	$6,754	$11,472
Distribution	367-UG Conductors & Devices	8.71%	$10,668	0.00%	$0	$10,668	7.61%	$10,428	$21,096
Distribution	368-Line Transformers	16.17%	$19,806	0.00%	$0	$19,806	13.51%	$18,524	$38,331
Distribution	369-Services	3.16%	$3,877	0.00%	$0	$3,877	4.33%	$5,937	$9,814
Distribution	370-Meters	1.91%	$2,341	0.00%	$0	$2,341	2.54%	$3,479	$5,820
Distribution	373-Street Lighting & Signals	1.08%	$1,321	0.00%	$0	$1,321	1.39%	$1,908	$3,229
	Total Distribution		$101,727		$0	$101,727		$119,188	$220,915
General	389-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
General	390-Struct & Imprv	0.32%	$387	1.02%	$3,288	$3,674	0.47%	$641	$4,315
General	391-Furn & Eq	2.04%	$2,504	0.00%	$0	$2,504	3.31%	$4,538	$7,042
General	392-Transp Eq	-0.29%	($351)	0.00%	$0	($351)	0.00%	$0	($351)
General	393-Stores Eq	0.02%	$28	0.00%	$0	$28	0.03%	$37	$65
General	394-Tools, Shp & Gar	0.50%	$616	0.00%	$0	$616	0.66%	$908	$1,524
General	395-Lab Eq	0.26%	$322	0.00%	$0	$322	0.22%	$305	$627
General	396-Power Op Eq	0.29%	$357	0.00%	$0	$357	0.15%	$201	$558
General	397-Comm Eq	0.59%	$726	0.00%	$0	$726	0.47%	$641	$1,368
General	398-Misc Eq	0.05%	$57	0.00%	$0	$57	0.03%	$42	$99
	Total General		$4,647		$3,288	$7,934		$7,313	$15,247
	Total		$122,500		$323,410	$445,909		$137,076	$582,985

UNS Electric, Inc.
Depreciation by Plant FERC Account
Test Year Ended June 30, 2006

Source: Eric Fowler 9/19/06 (this table is taken from the Revenue Requirement Model on 11/14/06)

Function	Plt Acct & Desc	Grand Total 0403	0404	403 & 404	0406	Sum	% of Total 403	% of Total 404	% of Total 406
Intangible	302-Franchises & Consents	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Intangible	303-Intangibles	$0.00	$386,336.30	$386,336.30	$289,869.21	$676,205.51	0.00%	98.98%	-7.40%
	Total Intangible	$0.00	$386,336.30	$386,336.30	$289,869.21	$676,205.51	0.00%	98.98%	-7.40%
Other Production	340-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Other Production	341-Struct & Imprv	$8,545.56	$0.00	$8,545.56	($2,069.16)	$6,476.40	0.06%	0.00%	0.05%
Other Production	342-Fuel Holders and Accessories	$15,279.00	$0.00	$15,279.00	($7,293.60)	$7,985.40	0.11%	0.00%	0.19%
Other Production	343-Prime Movers	$203,207.40	$0.00	$203,207.40	($84,240.36)	$118,967.04	1.42%	0.00%	2.15%
Other Production	344-Generators	$15,471.24	$0.00	$15,471.24	($7,722.48)	$7,748.76	0.11%	0.00%	0.20%
Other Production	345-Accessory Elec Eq	$37,074.36	$0.00	$37,074.36	($16,043.52)	$21,030.84	0.26%	0.00%	0.41%
Other Production	346-Misc Pwr Plt Eq	$9,237.36	$0.00	$9,237.36	($4,578.00)	$4,659.36	0.06%	0.00%	0.12%
	Total Other Production	$288,814.92	$0.00	$288,814.92	($121,947.12)	$166,867.80	2.02%	0.00%	3.11%
Transmission	350-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Transmission	352-Str & Impr	$7,225.56	$0.00	$7,225.56	($1,267.92)	$5,957.64	0.05%	0.00%	0.03%
Transmission	353-Station Eq	$518,281.56	$0.00	$518,281.56	($172,626.72)	$345,654.84	3.62%	0.00%	4.41%
Transmission	354-Towers & Fixtures	$21,299.76	$0.00	$21,299.76	($10,192.20)	$11,107.56	0.15%	0.00%	0.26%
Transmission	355-Poles & Fixtures	$733,454.57	$0.00	$733,454.57	($184,069.68)	$549,384.89	5.13%	0.00%	4.70%
Transmission	356-OH Conduct & Devices	$310,841.93	$0.00	$310,841.93	($100,769.40)	$210,072.53	2.17%	0.00%	2.57%
Transmission	358-UG Conductors & Devices	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Transmission	359-Roads & Trails	$3,695.52	$0.00	$3,695.52	($1,323.24)	$2,372.28	0.03%	0.00%	0.03%
	Total Transmission	$1,594,798.90	$0.00	$1,594,798.90	($470,249.16)	$1,124,549.74	11.15%	0.00%	12.00%
Distribution	360-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Distribution	361-Struct & Imprv	$126,971.87	$0.00	$126,971.87	($49,981.92)	$76,989.95	0.89%	0.00%	1.28%
Distribution	362-Station Eq	$1,383,463.45	$0.00	$1,383,463.45	($465,075.12)	$918,388.33	9.67%	0.00%	11.87%
Distribution	364-Poles, Towers & Fixtures	$3,231,613.80	$0.00	$3,231,613.80	($958,340.40)	$2,273,273.40	22.59%	0.00%	24.46%
Distribution	365-OH Conduct & Devices	$2,148,737.79	$0.00	$2,148,737.79	($589,444.32)	$1,559,293.47	15.02%	0.00%	15.04%
Distribution	366-UG Conduit	$551,074.38	$0.00	$551,074.38	($193,072.44)	$358,001.94	3.85%	0.00%	4.93%
Distribution	367-UG Conductors & Devices	$1,246,005.58	$0.00	$1,246,005.58	($298,124.28)	$947,881.30	8.71%	0.00%	7.61%
Distribution	368-Line Transformers	$2,313,392.75	$0.00	$2,313,392.75	($529,577.28)	$1,783,815.47	16.17%	0.00%	13.51%
Distribution	369-Services	$452,792.08	$0.00	$452,792.08	($169,727.40)	$283,064.68	3.16%	0.00%	4.33%
Distribution	370-Meters	$273,475.29	$0.00	$273,475.29	($99,460.44)	$174,014.85	1.91%	0.00%	2.54%
Distribution	373-Street Lighting & Signals	$154,301.97	$0.00	$154,301.97	($54,551.64)	$99,750.33	1.08%	0.00%	1.39%
	Total Distribution	$11,881,828.96	$0.00	$11,881,828.96	($3,407,355.24)	$8,474,473.72	83.04%	0.00%	86.95%
General	389-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
General	390-Struct & Imprv	$45,162.69	$3,968.04	$49,130.73	($18,317.76)	$30,812.97	0.32%	1.02%	0.47%
General	391-Furn & Eq	$292,500.08	$0.00	$292,500.08	($129,733.59)	$162,766.49	2.04%	0.00%	3.31%
General	392-Transp Eq	($40,958.88)	$0.00	($40,958.88)	$0.00	($40,958.88)	-0.29%	0.00%	0.00%
General	393-Stores Eq	$3,219.12	$0.00	$3,219.12	($1,062.00)	$2,157.12	0.02%	0.00%	0.03%
General	394-Tools, Shp & Gar	$71,986.90	$0.00	$71,986.90	($25,945.80)	$46,041.10	0.50%	0.00%	0.66%
General	395-Lab Eq	$37,641.04	$0.00	$37,641.04	($8,721.36)	$28,919.68	0.26%	0.00%	0.22%
General	396-Power Op Eq	$41,750.81	$0.00	$41,750.81	($5,736.60)	$36,014.21	0.29%	0.00%	0.15%
General	397-Comm Eq	$84,837.01	$0.00	$84,837.01	($18,331.08)	$66,505.93	0.59%	0.00%	0.47%
General	398-Misc Eq	$6,622.53	$0.00	$6,622.53	($1,201.80)	$5,420.73	0.05%	0.00%	0.03%
	Total General	$542,761.30	$3,968.04	$546,729.34	($209,049.99)	$337,679.35	3.79%	1.02%	5.33%
	Total Expense	$14,308,204.08	$390,304.34	$14,698,508.42	($3,918,732.30)	$10,779,776.12	100.00%	100.00%	100.00%

UNS Electric, Inc.
Depreciation Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
Intangible Plant:					
Acct. 302 Franchises and Consents	11,908	337	12,245	4.00%	490
Acct. 303 Misc. Intangible - WAPA Switchyard	3,466,687	98,123	3,564,810	3.13%	111,579
Acct. 303 Misc. Intangible - PC Software	1,151,869	32,603	1,184,472	20.00%	236,894
Acct. 303 Misc. Intangible - WAPA Fiber Optic	1,685,000	47,693	1,732,693	4.35%	75,372
Acct. 303 Misc. Intangible Plant	4,219,098	119,419	4,338,517	6.67%	289,379
Total	10,534,562	298,175	10,832,737		713,714
Other Production Plant:					
Acct. 340 Land & Land Rights	765,874	21,678	787,552	0.00%	-
Acct. 341 Structures & Improvements	1,141,496	32,309	1,173,805	2.07%	24,298
Acct. 342 Fuel Holders, Products & Access.	1,163,837	32,942	1,196,779	2.51%	30,039
Acct. 343 Prime Movers	15,413,970	436,285	15,850,255	2.53%	401,011
Acct. 344 Generators	4,850,576	137,293	4,987,869	2.33%	116,217
Acct. 345 Accessory Elec. Equipment	3,106,439	87,926	3,194,365	2.35%	75,068
Acct. 346 Misc. Power Plant Equip.	910,585	25,774	936,359	2.64%	24,720
Total	27,352,777	774,207	28,126,984		671,353
Transmission Plant:					
Acct. 350 Land	931,974	26,379	958,353	0.00%	-
Acct. 350 Land Rights	346,016	9,794	355,810	2.02%	7,187
Acct. 352 Structures & Improvements	191,668	5,425	197,093	3.13%	6,169
Acct. 353 Station Equipment	17,749,374	502,387	18,251,761	3.15%	574,930
Acct. 354 Towers & Fixtures	521,825	14,770	536,595	5.03%	26,991
Acct. 355 Poles & Fixtures	12,270,355	347,306	12,617,661	4.48%	565,271
Acct. 356 Overhead Conductors & Devices	11,237,572	318,074	11,555,646	2.66%	307,380
Acct. 359 Roads & Trails	183,860	5,204	189,064	2.02%	3,819
Total	43,432,644	1,229,339	44,661,983		1,491,747
Distribution Plant:					
Acct. 360 Land	1,147,687	32,485	1,180,172	0.00%	-
Acct. 360 Land Rights	90,198	2,553	92,751	2.03%	1,883
Acct. 361 Structures & Improvements	4,079,497	115,468	4,194,965	2.96%	124,171
Acct. 362 Station Equipment	32,948,469	932,590	33,881,059	4.09%	1,385,735
Acct. 364 Poles, Towers, and Fixtures	76,284,703	2,159,199	78,443,902	4.14%	3,247,578
Acct. 365 Overhead Conductors & Devices	49,721,006	1,407,328	51,128,334	4.13%	2,111,600
Acct. 366 Undeground Conduit	12,601,063	356,667	12,957,730	3.79%	491,098
Acct. 367 Underground Conductors & Devices	27,259,007	771,552	28,030,559	4.40%	1,233,345
Acct. 368 Line Transformers	47,498,916	1,344,432	48,843,348	4.63%	2,261,447
Acct. 369 Services (Overhead)	7,345,320	207,906	7,553,226	3.77%	284,757
Acct. 369 Services (Underground)	3,350,247	94,827	3,445,074	3.75%	129,190
Acct. 370 Meters	9,796,741	277,292	10,074,033	3.11%	313,302
Acct. 373 St. Lghtng & Signal Systems	3,811,070	107,870	3,918,940	4.04%	158,325
Total	275,933,924	7,810,169	283,744,093		11,742,431

UNS Electric, Inc.
Depreciation Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
General Plant:					
Acct. 389 Land & Land Rights	57,580	1,630	59,210	0.00%	-
Acct. 390 Structures & Improvements	1,852,505	52,434	1,904,939	2.65%	50,481
Acct. 391 Office Furniture & Equipment	2,300,322	65,109	2,365,431	4.76%	112,595
Acct. 391 Computer Equipment - PCs	920,167	26,045	946,212	20.00%	189,242
Acct. 392 Transportation Equipment - Class 1	366,331	10,369	376,700	12.75%	48,029
Acct. 392 Transportation Equipment - Class 2	1,151,599	32,595	1,184,194	16.99%	201,195
Acct. 392 Transportation Equipment - Class 3	1,185,238	33,548	1,218,786	20.21%	246,317
Acct. 392 Transportation Equipment - Class 4	5,641,612	159,683	5,801,295	13.47%	781,434
Acct. 392 Transportation Equipment - Class 5	1,995,626	56,485	2,052,111	12.55%	257,540
Acct. 393 Stores Equipment	122,871	3,478	126,349	3.03%	3,828
Acct. 394 Tools, Shop, & Garage Equip.	2,442,774	69,141	2,511,915	3.45%	86,661
Acct. 395 Laboratory Equipment	1,308,029	37,023	1,345,052	2.50%	33,626
Acct. 396 Power Operated Equip.	1,209,325	34,229	1,243,554	6.92%	86,054
Acct. 397 Communications Equip.	2,262,795	64,047	2,326,842	4.35%	101,218
Acct. 398 Misc. Equipment	121,811	3,448	125,259	5.56%	6,964
Total	22,938,585	649,264	23,587,849		2,205,184

	Total Annualized Depreciation	16,824,429
	Less: Previously Recognized Depreciation on CWIP Requested in Rate Base	(449,816)
Pro Forma Acct. 392 Depreciation X 58.5%	Less: Vehicle Depreciation Charged to CWIP	(897,691)
	Total Annualized Depreciation Expense	15,476,922
	Test Year Recorded Depreciation Expense	14,698,509
Test Year Acct. 392 depreciation X 41.5%	Add: Vehicle Depreciation cleared to O&M	332,503
	Test Year Depreciation Expense	15,031,012
	Adjustment Required	445,910

	Acct. 403	Acct. 404	O&M Exp.	Total
Test Year Recorded	14,308,205	390,304	332,503	15,031,012
T.Y. As Adjusted -				
Annualized	16,110,715	713,714		16,824,429
Less; Depr. On CWIP previously recognized	(449,816)			(449,816)
Vehicle Depreciation Chgs CWIP	(1,534,515)		636,824	(897,691)
	14,126,384	713,714	636,824	15,476,922
Adjustment amount	(181,821)	323,410	304,321	445,910
Net 403	122,500			

Note--for purposes of the adjustment, vehicle depreciation in O&M is treated as being in Acct. 403

UNS Electric, Inc.
Acquisition Discount Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
Intangible Plant:					
Acct. 302 Franchises and Consents	(6,563)	670	(5,893)	4.00%	(236)
Acct. 303 Misc. Intangible - WAPA Switchyard	-	-	-	3.13%	-
Acct. 303 Misc. Intangible - PC Software	(283,245)	28,910	(254,335)	20.00%	(50,867)
Acct. 303 Misc. Intangible - WAPA Fiber Optic	-	-	-	4.35%	-
Acct. 303 Misc. Intangible Plant	(2,178,032)	222,305	(1,955,727)	6.67%	(130,447)
Total	(2,467,840)	251,885	(2,215,955)		(181,550)
Other Production Plant:					
Acct. 340 Land & Land Rights	(422,116)	43,084	(379,032)	0.00%	-
Acct. 341 Structures & Improvements	(149,938)	15,304	(134,634)	2.07%	(2,787)
Acct. 342 Fuel Holders, Products & Access.	(301,386)	30,762	(270,624)	2.51%	(6,793)
Acct. 343 Prime Movers	(3,600,013)	367,442	(3,232,571)	2.53%	(81,784)
Acct. 344 Generators	(1,152,606)	117,643	(1,034,963)	2.33%	(24,115)
Acct. 345 Accessory Elec. Equipment	(729,249)	74,432	(654,817)	2.35%	(15,388)
Acct. 346 Misc. Power Plant Equip.	(244,813)	24,987	(219,826)	2.64%	(5,803)
Total	(6,600,121)	673,654	(5,926,467)		(136,670)
Transmission Plant:					
Acct. 350 Land	(513,664)	52,428	(461,236)	0.00%	-
Acct. 350 Land Rights	(190,708)	19,465	(171,243)	2.02%	(3,459)
Acct. 352 Structures & Improvements	(33,630)	3,433	(30,197)	3.13%	(945)
Acct. 353 Station Equipment	(5,911,873)	603,407	(5,308,466)	3.15%	(167,217)
Acct. 354 Towers & Fixtures	(236,215)	24,110	(212,105)	5.03%	(10,669)
Acct. 355 Poles & Fixtures	(3,190,115)	325,605	(2,864,510)	4.48%	(128,330)
Acct. 356 Overhead Conductors & Devices	(3,718,427)	379,529	(3,338,898)	2.66%	(88,815)
Acct. 359 Roads & Trails	(65,832)	6,719	(59,113)	2.02%	(1,194)
Total	(13,860,464)	1,414,696	(12,445,768)		(400,629)
Distribution Plant:					
Acct. 360 Land	(595,245)	60,755	(534,490)	0.00%	-
Acct. 360 Land Rights	(47,740)	4,873	(42,867)	2.03%	(870)
Acct. 361 Structures & Improvements	(1,561,939)	159,422	(1,402,517)	2.96%	(41,515)
Acct. 362 Station Equipment	(9,648,864)	984,830	(8,664,034)	4.09%	(354,359)
Acct. 364 Poles, Towers, and Fixtures	(22,655,802)	2,312,406	(20,343,396)	4.14%	(842,217)
Acct. 365 Overhead Conductors & Devices	(13,519,363)	1,379,880	(12,139,483)	4.13%	(501,361)
Acct. 366 Undeground Conduit	(4,511,041)	460,428	(4,050,613)	3.79%	(153,518)
Acct. 367 Underground Conductors & Devices	(5,562,021)	567,698	(4,994,323)	4.40%	(219,750)
Acct. 368 Line Transformers	(10,741,931)	1,096,396	(9,645,535)	4.63%	(446,588)
Acct. 369 Services (Overhead)	(2,577,155)	263,042	(2,314,113)	3.77%	(87,242)
Acct. 369 Services (Underground)	(1,435,315)	146,498	(1,288,817)	3.75%	(48,331)
Acct. 370 Meters	(3,060,324)	312,358	(2,747,966)	3.11%	(85,462)
Acct. 373 St. Lghtng & Signal Systems	(1,198,936)	122,372	(1,076,564)	4.04%	(43,493)
Total	(77,115,676)	7,870,958	(69,244,718)		(2,824,706)

UNS Electric, Inc.
Acquisition Discount Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
General Plant:					
Acct. 389 Land & Land Rights	(31,736)	3,239	(28,497)	0.00%	-
Acct. 390 Structures & Improvements	(633,826)	64,693	(569,133)	2.65%	(15,082)
Acct. 391 Office Furniture & Equipment	(460,920)	47,045	(413,875)	4.76%	(19,700)
Acct. 391 Computer Equipment - PCs	(673,037)	68,695	(604,342)	20.00%	(120,868)
Acct. 392 Transportation Equipment - Class 1	(51,192)	39,563	(11,629)	12.75%	(1,483)
Acct. 392 Transportation Equipment - Class 2	(16,191)	12,513	(3,678)	16.99%	(625)
Acct. 392 Transportation Equipment - Class 3	(92,982)	71,860	(21,122)	20.21%	(4,269)
Acct. 392 Transportation Equipment - Class 4	(362,404)	280,080	(82,324)	13.47%	(11,089)
Acct. 392 Transportation Equipment - Class 5	-	-	-	12.55%	-
Acct. 393 Stores Equipment	(40,540)	4,138	(36,402)	3.03%	(1,103)
Acct. 394 Tools, shop, & Garage Equip.	(859,128)	87,689	(771,439)	3.45%	(26,615)
Acct. 395 Laboratory Equipment	(361,880)	36,936	(324,944)	2.50%	(8,124)
Acct. 396 Power Operated Equip.	(172,278)	17,584	(154,694)	6.92%	(10,705)
Acct. 397 Communications Equip.	(443,854)	45,303	(398,551)	4.35%	(17,337)
Acct. 398 Misc. Equipment	(22,054)	2,251	(19,803)	5.56%	(1,101)
Total	(4,222,022)	781,589	(3,440,433)		(238,101)

Total Annualized Amortization-Acq. Discount	(3,781,656)
Test Year Amount per Books	(3,918,732)
Adjustment Required (FERC 406)	137,076

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Detail by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 28, 2006
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
FERC 403 & 404			
303	Miscellaneous Intangible Plant	$320,122	
341	Structures & Improvements	$34	
342	Fuel Holders, Producers, & Accessories	$62	
343	Prime Movers	$818	
344	Generators	$62	
345	Accessory Electric Equipment	$149	
346	Misc. Power Plant Equipment	$37	
352	Structures & Improvements	$29	
353	Station Equipment	$2,087	
354	Towers & Fixtures	$86	
355	Poles & Fixtures	$2,954	
356	Overhead Conductors & Devices	$1,252	
359	Roads & Trails	$15	
361	Structures & Improvements	$511	
362	Station Equipment	$5,572	
364	Poles, Towers, & Fixtures	$13,016	
365	Overhead Conductors & Devices	$8,654	
366	Underground Conduit	$2,220	
367	Underground Conductors & Devices	$5,018	
368	Line Transformers	$9,317	
369	Services	$1,824	
370	Meters	$1,101	
373	Street Lights and Signal Systems	$621	
390	Structures & Improvements	$3,469	
391	Office Furniture & Equipment	$1,178	
392	Transportation Equipment		$165
393	Stores Equipment	$13	
394	Tools, Shop, & Garage Equipment	$290	
395	Laboratory Equipment	$152	
396	Power Operated Equipment	$168	
397	Communication Equipment	$342	
398	Miscellaneous Equipment	$27	
FERC 406			
303	Miscellaneous Intangible Plant		$10,270
341	Structures & Improvements	$73	
342	Fuel Holders, Producers, & Accessories	$258	
343	Prime Movers	$2,985	
344	Generators	$274	
345	Accessory Electric Equipment	$568	
346	Misc. Power Plant Equipment	$162	
352	Structures & Improvements	$45	
353	Station Equipment	$6,116	
354	Towers & Fixtures	$361	

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Detail by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 28, 2006
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
355	Poles & Fixtures	$6,522	
356	Overhead Conductors & Devices	$3,570	
359	Roads & Trails	$47	
361	Structures & Improvements	$1,771	
362	Station Equipment	$16,478	
364	Poles, Towers, & Fixtures	$33,955	
365	Overhead Conductors & Devices	$20,884	
366	Underground Conduit	$6,841	
367	Underground Conductors & Devices	$10,563	
368	Line Transformers	$18,763	
369	Services	$6,014	
370	Meters	$3,524	
373	Street Lights and Signal Systems	$1,933	
390	Structures & Improvements	$649	
391	Office Furniture & Equipment	$4,597	
393	Stores Equipment	$38	
394	Tools, Shop, & Garage Equipment	$919	
395	Laboratory Equipment	$309	
396	Power Operated Equipment	$203	
397	Communication Equipment	$649	
398	Miscellaneous Equipment	$43	
	ENTRY TOTAL	**$530,312**	**$10,436**

NET ENTRY **$519,876**

(rounding variance of $5 with unallocated amounts is ignored - immaterial)

Reason for Adjustment

To adjust test year recorded depreciation to reflect annualized depreciation based on ending plant balances and the depreciation rates resulting from Dr. White's study. This adjustment excludes the effects of depreciation on the level of CWIP requested for inclusion in rate base.

To adjust test year recorded amortization expense to reflect acquisition discount in Decision No. 66028 and the depreciation rates resulting from Dr. White's study.

UNS ELECTRIC, INC.
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED JUNE 30, 2006

ADJUSTMENT NAME:	Depreciation Annualization - Summary by FERC
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	November 26, 2006
PREPARED BY:	E. Fowler
CHECKED BY:	C. Dabelstein
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
403	Depreciation Expense	$57,628	
404	Amortization of Utility Plant	$323,410	
406	Amortization of Utility Plant Acquisition Adjustments	$138,843	
	ENTRY TOTAL	**$519,881**	**$0**

Reason for Adjustment

To adjust test year recorded depreciation and amortization expense to reflect the final adjusted balances

UNS Electric, Inc.
Allocation of Depreciation & Amortization Pro Forma Adjustment to FERC Accounts
Test Year Ended June 30, 2006

Function	Plt Acct & Desc	403 %	403 $57,628	403 %	404 $323,410	Total 403 & 404 $381,038	406 %	406 $138,843	Total $519,881
Intangible	302-Franchises & Consents	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Intangible	303-Intangibles	0.00%	$0	98.98%	$320,122	$320,122	-7.40%	($10,270)	$309,852
	Total Intangible		$0		$320,122	$320,122		($10,270)	$309,852
Other Production	340-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Other Production	341-Struct & Imprv	0.06%	$34	0.00%	$0	$34	0.05%	$73	$108
Other Production	342-Fuel Holders and Accessories	0.11%	$62	0.00%	$0	$62	0.19%	$258	$320
Other Production	343-Prime Movers	1.42%	$818	0.00%	$0	$818	2.15%	$2,985	$3,803
Other Production	344-Generators	0.11%	$62	0.00%	$0	$62	0.20%	$274	$336
Other Production	345-Accessory Elec Eq	0.26%	$149	0.00%	$0	$149	0.41%	$568	$718
Other Production	346-Misc Pwr Plt Eq	0.06%	$37	0.00%	$0	$37	0.12%	$162	$199
	Total Other Production		$1,163		$0	$1,163		$4,321	$5,484
Transmission	350-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Transmission	352-Str & Impr	0.05%	$29	0.00%	$0	$29	0.03%	$45	$74
Transmission	353-Station Eq	3.62%	$2,087	0.00%	$0	$2,087	4.41%	$6,116	$8,203
Transmission	354-Towers & Fixtures	0.15%	$86	0.00%	$0	$86	0.26%	$361	$447
Transmission	355-Poles & Fixtures	5.13%	$2,954	0.00%	$0	$2,954	4.70%	$6,522	$9,476
Transmission	356-OH Conduct & Devices	2.17%	$1,252	0.00%	$0	$1,252	2.57%	$3,570	$4,822
Transmission	358-UG Conductors & Devices	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Transmission	359-Roads & Trails	0.03%	$15	0.00%	$0	$15	0.03%	$47	$62
	Total Transmission		$6,423		$0	$6,423		$16,661	$23,084
Distribution	360-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
Distribution	361-Struct & Imprv	0.89%	$511	0.00%	$0	$511	1.28%	$1,771	$2,282
Distribution	362-Station Eq	9.67%	$5,572	0.00%	$0	$5,572	11.87%	$16,478	$22,050
Distribution	364-Poles, Towers & Fixtures	22.59%	$13,016	0.00%	$0	$13,016	24.46%	$33,955	$46,970
Distribution	365-OH Conduct & Devices	15.02%	$8,654	0.00%	$0	$8,654	15.04%	$20,884	$29,539
Distribution	366-UG Conduit	3.85%	$2,220	0.00%	$0	$2,220	4.93%	$6,841	$9,060
Distribution	367-UG Conductors & Devices	8.71%	$5,018	0.00%	$0	$5,018	7.61%	$10,563	$15,581
Distribution	368-Line Transformers	16.17%	$9,317	0.00%	$0	$9,317	13.51%	$18,763	$28,081
Distribution	369-Services	3.16%	$1,824	0.00%	$0	$1,824	4.33%	$6,014	$7,837
Distribution	370-Meters	1.91%	$1,101	0.00%	$0	$1,101	2.54%	$3,524	$4,625
Distribution	373-Street Lighting & Signals	1.08%	$621	0.00%	$0	$621	1.39%	$1,933	$2,554
	Total Distribution		$47,855		$0	$47,855		$120,725	$168,580
General	389-Land & Land Rights	0.00%	$0	0.00%	$0	$0	0.00%	$0	$0
General	390-Struct & Imprv	0.32%	$182	1.02%	$3,288	$3,469	0.47%	$649	$4,118
General	391-Furn & Eq	2.04%	$1,178	0.00%	$0	$1,178	3.31%	$4,597	$5,775
General	392-Transp Eq	-0.29%	($165)	0.00%	$0	($165)	0.00%	$0	($165)
General	393-Stores Eq	0.02%	$13	0.00%	$0	$13	0.03%	$38	$51
General	394-Tools, Shp & Gar	0.50%	$290	0.00%	$0	$290	0.66%	$919	$1,209
General	395-Lab Eq	0.26%	$152	0.00%	$0	$152	0.22%	$309	$461
General	396-Power Op Eq	0.29%	$168	0.00%	$0	$168	0.15%	$203	$371
General	397-Comm Eq	0.59%	$342	0.00%	$0	$342	0.47%	$649	$991
General	398-Misc Eq	0.05%	$27	0.00%	$0	$27	0.03%	$43	$69
	Total General		$2,186		$3,288	$5,473		$7,407	$12,880
	Total		$57,628		$323,410	$381,037		$138,843	$519,880

UNS Electric, Inc.
Depreciation by Plant FERC Account
Test Year Ended June 30, 2006

Source: Eric Fowler 9/19/06 (this table is taken from the Revenue Requirement Model on 11/14/06)

		Grand Total					% of Total	% of Total	% of Total
Function	Plt Acct & Desc	0403	0404	403 & 404	0406	Sum	403	404	406
Intangible	302-Franchises & Consents	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Intangible	303-Intangibles	$0.00	$386,336.30	$386,336.30	$289,869.21	$676,205.51	0.00%	98.98%	-7.40%
	Total Intangible	$0.00	$386,336.30	$386,336.30	$289,869.21	$676,205.51	0.00%	98.98%	-7.40%
Other Production	340-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Other Production	341-Struct & Imprv	$8,545.56	$0.00	$8,545.56	($2,069.16)	$6,476.40	0.06%	0.00%	0.05%
Other Production	342-Fuel Holders and Accessories	$15,279.00	$0.00	$15,279.00	($7,293.60)	$7,985.40	0.11%	0.00%	0.19%
Other Production	343-Prime Movers	$203,207.40	$0.00	$203,207.40	($84,240.36)	$118,967.04	1.42%	0.00%	2.15%
Other Production	344-Generators	$15,471.24	$0.00	$15,471.24	($7,722.48)	$7,748.76	0.11%	0.00%	0.20%
Other Production	345-Accessory Elec Eq	$37,074.36	$0.00	$37,074.36	($16,043.52)	$21,030.84	0.26%	0.00%	0.41%
Other Production	346-Misc Pwr Plt Eq	$9,237.36	$0.00	$9,237.36	($4,578.00)	$4,659.36	0.06%	0.00%	0.12%
	Total Other Production	$288,814.92	$0.00	$288,814.92	($121,947.12)	$166,867.80	2.02%	0.00%	3.11%
Transmission	350-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Transmission	352-Str & Impr	$7,225.56	$0.00	$7,225.56	($1,267.92)	$5,957.64	0.05%	0.00%	0.03%
Transmission	353-Station Eq	$518,281.56	$0.00	$518,281.56	($172,626.72)	$345,654.84	3.62%	0.00%	4.41%
Transmission	354-Towers & Fixtures	$21,299.76	$0.00	$21,299.76	($10,192.20)	$11,107.56	0.15%	0.00%	0.26%
Transmission	355-Poles & Fixtures	$733,454.57	$0.00	$733,454.57	($184,069.68)	$549,384.89	5.13%	0.00%	4.70%
Transmission	356-OH Conduct & Devices	$310,841.93	$0.00	$310,841.93	($100,769.40)	$210,072.53	2.17%	0.00%	2.57%
Transmission	358-UG Conductors & Devices	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Transmission	359-Roads & Trails	$3,695.52	$0.00	$3,695.52	($1,323.24)	$2,372.28	0.03%	0.00%	0.03%
	Total Transmission	$1,594,798.90	$0.00	$1,594,798.90	($470,249.16)	$1,124,549.74	11.15%	0.00%	12.00%
Distribution	360-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
Distribution	361-Struct & Imprv	$126,971.87	$0.00	$126,971.87	($49,981.92)	$76,989.95	0.89%	0.00%	1.28%
Distribution	362-Station Eq	$1,383,463.45	$0.00	$1,383,463.45	($465,075.12)	$918,388.33	9.67%	0.00%	11.87%
Distribution	364-Poles, Towers & Fixtures	$3,231,613.80	$0.00	$3,231,613.80	($958,340.40)	$2,273,273.40	22.59%	0.00%	24.46%
Distribution	365-OH Conduct & Devices	$2,148,737.79	$0.00	$2,148,737.79	($589,444.32)	$1,559,293.47	15.02%	0.00%	15.04%
Distribution	366-UG Conduit	$551,074.38	$0.00	$551,074.38	($193,072.44)	$358,001.94	3.85%	0.00%	4.93%
Distribution	367-UG Conductors & Devices	$1,246,005.58	$0.00	$1,246,005.58	($298,124.28)	$947,881.30	8.71%	0.00%	7.61%
Distribution	368-Line Transformers	$2,313,392.75	$0.00	$2,313,392.75	($529,577.28)	$1,783,815.47	16.17%	0.00%	13.51%
Distribution	369-Services	$452,792.08	$0.00	$452,792.08	($169,727.40)	$283,064.68	3.16%	0.00%	4.33%
Distribution	370-Meters	$273,475.29	$0.00	$273,475.29	($99,460.44)	$174,014.85	1.91%	0.00%	2.54%
Distribution	373-Street Lighting & Signals	$154,301.97	$0.00	$154,301.97	($54,551.64)	$99,750.33	1.08%	0.00%	1.39%
	Total Distribution	$11,881,828.96	$0.00	$11,881,828.96	($3,407,355.24)	$8,474,473.72	83.04%	0.00%	86.95%
General	389-Land & Land Rights	$0.00	$0.00	$0.00	$0.00	$0.00	0.00%	0.00%	0.00%
General	390-Struct & Imprv	$45,162.69	$3,968.04	$49,130.73	($18,317.76)	$30,812.97	0.32%	1.02%	0.47%
General	391-Furn & Eq	$292,500.08	$0.00	$292,500.08	($129,733.59)	$162,766.49	2.04%	0.00%	3.31%
General	392-Transp Eq	($40,958.88)	$0.00	($40,958.88)	$0.00	($40,958.88)	-0.29%	0.00%	0.00%
General	393-Stores Eq	$3,219.12	$0.00	$3,219.12	($1,062.00)	$2,157.12	0.02%	0.00%	0.03%
General	394-Tools, Shp & Gar	$71,986.90	$0.00	$71,986.90	($25,945.80)	$46,041.10	0.50%	0.00%	0.66%
General	395-Lab Eq	$37,641.04	$0.00	$37,641.04	($8,721.36)	$28,919.68	0.26%	0.00%	0.22%
General	396-Power Op Eq	$41,750.81	$0.00	$41,750.81	($5,736.60)	$36,014.21	0.29%	0.00%	0.15%
General	397-Comm Eq	$84,837.01	$0.00	$84,837.01	($18,331.08)	$66,505.93	0.59%	0.00%	0.47%
General	398-Misc Eq	$6,622.53	$0.00	$6,622.53	($1,201.80)	$5,420.73	0.05%	0.00%	0.03%
	Total General	$542,761.30	$3,968.04	$546,729.34	($209,049.99)	$337,679.35	3.79%	1.02%	5.33%
	Total Expense	$14,308,204.08	$390,304.34	$14,698,508.42	($3,918,732.30)	$10,779,776.12	100.00%	100.00%	100.00%

UNS Electric, Inc.
Depreciation Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
Intangible Plant:					
Acct. 302 Franchises and Consents	11,908	337	12,245	4.00%	490
Acct. 303 Misc. Intangible - WAPA Switchyard	3,466,687	98,123	3,564,810	3.13%	111,579
Acct. 303 Misc. Intangible - PC Software	1,151,869	32,603	1,184,472	20.00%	236,894
Acct. 303 Misc. Intangible - WAPA Fiber Optic	1,685,000	47,693	1,732,693	4.35%	75,372
Acct. 303 Misc. Intangible Plant	4,219,098	119,419	4,338,517	6.67%	289,379
Total	10,534,562	298,175	10,832,737		713,714
Other Production Plant:					
Acct. 340 Land & Land Rights	765,874	21,678	787,552	0.00%	-
Acct. 341 Structures & Improvements	1,141,496	32,309	1,173,805	2.07%	24,298
Acct. 342 Fuel Holders, Products & Access.	1,163,837	32,942	1,196,779	2.51%	30,039
Acct. 343 Prime Movers	15,413,970	436,285	15,850,255	2.53%	401,011
Acct. 344 Generators	4,850,576	137,293	4,987,869	2.33%	116,217
Acct. 345 Accessory Elec. Equipment	3,106,439	87,926	3,194,365	2.35%	75,068
Acct. 346 Misc. Power Plant Equip.	910,585	25,774	936,359	2.64%	24,720
Total	27,352,777	774,207	28,126,984		671,353
Transmission Plant:					
Acct. 350 Land	931,974	26,379	958,353	0.00%	-
Acct. 350 Land Rights	346,016	9,794	355,810	2.02%	7,187
Acct. 352 Structures & Improvements	191,668	5,425	197,093	3.13%	6,169
Acct. 353 Station Equipment	17,749,374	502,387	18,251,761	3.15%	574,930
Acct. 354 Towers & Fixtures	521,825	14,770	536,595	5.03%	26,991
Acct. 355 Poles & Fixtures	12,270,355	347,306	12,617,661	4.48%	565,271
Acct. 356 Overhead Conductors & Devices	11,237,572	318,074	11,555,646	2.66%	307,380
Acct. 359 Roads & Trails	183,860	5,204	189,064	2.02%	3,819
Total	43,432,644	1,229,339	44,661,983		1,491,747
Distribution Plant:					
Acct. 360 Land	1,147,687	32,485	1,180,172	0.00%	-
Acct. 360 Land Rights	90,198	2,553	92,751	2.03%	1,883
Acct. 361 Structures & Improvements	4,079,497	115,468	4,194,965	2.96%	124,171
Acct. 362 Station Equipment	32,948,469	932,590	33,881,059	4.09%	1,385,735
Acct. 364 Poles, Towers, and Fixtures	76,284,703	2,159,199	78,443,902	4.14%	3,247,578
Acct. 365 Overhead Conductors & Devices	49,721,006	1,407,328	51,128,334	4.13%	2,111,600
Acct. 366 Undeground Conduit	12,601,063	356,667	12,957,730	3.79%	491,098
Acct. 367 Underground Conductors & Devices	27,259,007	771,552	28,030,559	4.40%	1,233,345
Acct. 368 Line Transformers	47,498,916	1,344,432	48,843,348	4.63%	2,261,447
Acct. 369 Services (Overhead)	7,345,320	207,906	7,553,226	3.77%	284,757
Acct. 369 Services (Underground)	3,350,247	94,827	3,445,074	3.75%	129,190
Acct. 370 Meters	9,796,741	277,292	10,074,033	3.11%	313,302
Acct. 373 St. Lghtng & Signal Systems	3,811,070	107,870	3,918,940	4.04%	158,325
Total	275,933,924	7,810,169	283,744,093		11,742,431

UNS Electric, Inc.
Depreciation Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
General Plant:					
Acct. 389 Land & Land Rights	57,580	1,630	59,210	0.00%	-
Acct. 390 Structures & Improvements	1,852,505	52,434	1,904,939	2.65%	50,481
Acct. 391 Office Furniture & Equipment	2,300,322	65,109	2,365,431	4.76%	112,595
Acct. 391 Computer Equipment - PCs	920,167	26,045	946,212	20.00%	189,242
Acct. 392 Transportation Equipment - Class 1	366,331	10,369	376,700	11.48%	43,245
Acct. 392 Transportation Equipment - Class 2	1,151,599	32,595	1,184,194	15.29%	181,063
Acct. 392 Transportation Equipment - Class 3	1,185,238	33,548	1,218,786	18.69%	227,791
Acct. 392 Transportation Equipment - Class 4	5,641,612	159,683	5,801,295	11.97%	694,415
Acct. 392 Transportation Equipment - Class 5	1,995,626	56,485	2,052,111	11.29%	231,683
Acct. 393 Stores Equipment	122,871	3,478	126,349	3.03%	3,828
Acct. 394 Tools, Shop, & Garage Equip.	2,442,774	69,141	2,511,915	3.45%	86,661
Acct. 395 Laboratory Equipment	1,308,029	37,023	1,345,052	2.50%	33,626
Acct. 396 Power Operated Equip.	1,209,325	34,229	1,243,554	6.92%	86,054
Acct. 397 Communications Equip.	2,262,795	64,047	2,326,842	4.35%	101,218
Acct. 398 Misc. Equipment	121,811	3,448	125,259	5.56%	6,964
Total	22,938,585	649,264	23,587,849		2,048,866

	Total Annualized Depreciation	16,668,111
	Less: Previously Recognized Depreciation on CWIP Requested in Rate Base	(449,816)
Pro Forma Acct. 392 Depreciation X 58.5%	Less: Vehicle Depreciation Charged to CWIP	(806,245)
	Total Annualized Depreciation Expense	15,412,050
	Test Year Recorded Depreciation Expense	14,698,509
Test Year Acct. 392 depreciation X 41.5%	Add: Vehicle Depreciation cleared to O&M	332,503
	Test Year Depreciation Expense	15,031,012
	Adjustment Required	381,038

	Acct. 403	Acct. 404	O&M Exp.	Total
Test Year Recorded	14,308,205	390,304	332,503	15,031,012
T.Y. As Adjusted -				
Annualized	15,954,397	713,714		16,668,111
Less; Depr. On CWIP previously recognized	(449,816)			(449,816)
Vehicle Depreciation Chgs CWIP	(1,378,197)		571,952	(806,245)
	14,126,384	713,714	571,952	15,412,050
Adjustment amount	(181,821)	323,410	239,449	381,038
Net 403	57,628			

Note--for purposes of the adjustment, vehicle depreciation in O&M is treated as being in Acct. 403

UNS Electric, Inc.
Acquisition Discount Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
Intangible Plant:					
Acct. 302 Franchises and Consents	(6,563)	670	(5,893)	4.00%	(236)
Acct. 303 Misc. Intangible - WAPA Switchyard	-	-	-	3.13%	-
Acct. 303 Misc. Intangible - PC Software	(283,245)	28,910	(254,335)	20.00%	(50,867)
Acct. 303 Misc. Intangible - WAPA Fiber Optic	-	-	-	4.35%	-
Acct. 303 Misc. Intangible Plant	(2,178,032)	222,305	(1,955,727)	6.67%	(130,447)
Total	(2,467,840)	251,885	(2,215,955)		(181,550)
Other Production Plant:					
Acct. 340 Land & Land Rights	(422,116)	43,084	(379,032)	0.00%	-
Acct. 341 Structures & Improvements	(149,938)	15,304	(134,634)	2.07%	(2,787)
Acct. 342 Fuel Holders, Products & Access.	(301,386)	30,762	(270,624)	2.51%	(6,793)
Acct. 343 Prime Movers	(3,600,013)	367,442	(3,232,571)	2.53%	(81,784)
Acct. 344 Generators	(1,152,606)	117,643	(1,034,963)	2.33%	(24,115)
Acct. 345 Accessory Elec. Equipment	(729,249)	74,432	(654,817)	2.35%	(15,388)
Acct. 346 Misc. Power Plant Equip.	(244,813)	24,987	(219,826)	2.64%	(5,803)
Total	(6,600,121)	673,654	(5,926,467)		(136,670)
Transmission Plant:					
Acct. 350 Land	(513,664)	52,428	(461,236)	0.00%	-
Acct. 350 Land Rights	(190,708)	19,465	(171,243)	2.02%	(3,459)
Acct. 352 Structures & Improvements	(33,630)	3,433	(30,197)	3.13%	(945)
Acct. 353 Station Equipment	(5,911,873)	603,407	(5,308,466)	3.15%	(167,217)
Acct. 354 Towers & Fixtures	(236,215)	24,110	(212,105)	5.03%	(10,669)
Acct. 355 Poles & Fixtures	(3,190,115)	325,605	(2,864,510)	4.48%	(128,330)
Acct. 356 Overhead Conductors & Devices	(3,718,427)	379,529	(3,338,898)	2.66%	(88,815)
Acct. 359 Roads & Trails	(65,832)	6,719	(59,113)	2.02%	(1,194)
Total	(13,860,464)	1,414,696	(12,445,768)		(400,629)
Distribution Plant:					
Acct. 360 Land	(595,245)	60,755	(534,490)	0.00%	-
Acct. 360 Land Rights	(47,740)	4,873	(42,867)	2.03%	(870)
Acct. 361 Structures & Improvements	(1,561,939)	159,422	(1,402,517)	2.96%	(41,515)
Acct. 362 Station Equipment	(9,648,864)	984,830	(8,664,034)	4.09%	(354,359)
Acct. 364 Poles, Towers, and Fixtures	(22,655,802)	2,312,406	(20,343,396)	4.14%	(842,217)
Acct. 365 Overhead Conductors & Devices	(13,519,363)	1,379,880	(12,139,483)	4.13%	(501,361)
Acct. 366 Undeground Conduit	(4,511,041)	460,428	(4,050,613)	3.79%	(153,518)
Acct. 367 Underground Conductors & Devices	(5,562,021)	567,698	(4,994,323)	4.40%	(219,750)
Acct. 368 Line Transformers	(10,741,931)	1,096,396	(9,645,535)	4.63%	(446,588)
Acct. 369 Services (Overhead)	(2,577,155)	263,042	(2,314,113)	3.77%	(87,242)
Acct. 369 Services (Underground)	(1,435,315)	146,498	(1,288,817)	3.75%	(48,331)
Acct. 370 Meters	(3,060,324)	312,358	(2,747,966)	3.11%	(85,462)
Acct. 373 St. Lghtng & Signal Systems	(1,198,936)	122,372	(1,076,564)	4.04%	(43,493)
Total	(77,115,676)	7,870,958	(69,244,718)		(2,824,706)

UNS Electric, Inc.
Acquisition Discount Annualization Adjustment

Source: Tax Services

Description	Balance at 6/30/06	Rate Case Adjustments	Adjusted Balance	Depreciation Rate %	Annualized Depreciation
General Plant:					
Acct. 389 Land & Land Rights	(31,736)	3,239	(28,497)	0.00%	-
Acct. 390 Structures & Improvements	(633,826)	64,693	(569,133)	2.65%	(15,082)
Acct. 391 Office Furniture & Equipment	(460,920)	47,045	(413,875)	4.76%	(19,700)
Acct. 391 Computer Equipment - PCs	(673,037)	68,695	(604,342)	20.00%	(120,868)
Acct. 392 Transportation Equipment - Class 1	(51,192)	39,563	(11,629)	11.48%	(1,335)
Acct. 392 Transportation Equipment - Class 2	(16,191)	12,513	(3,678)	15.29%	(562)
Acct. 392 Transportation Equipment - Class 3	(92,982)	71,860	(21,122)	18.69%	(3,948)
Acct. 392 Transportation Equipment - Class 4	(362,404)	280,080	(82,324)	11.97%	(9,854)
Acct. 392 Transportation Equipment - Class 5	-	-	-	11.29%	-
Acct. 393 Stores Equipment	(40,540)	4,138	(36,402)	3.03%	(1,103)
Acct. 394 Tools, shop, & Garage Equip.	(859,128)	87,689	(771,439)	3.45%	(26,615)
Acct. 395 Laboratory Equipment	(361,880)	36,936	(324,944)	2.50%	(8,124)
Acct. 396 Power Operated Equip.	(172,278)	17,584	(154,694)	6.92%	(10,705)
Acct. 397 Communications Equip.	(443,854)	45,303	(398,551)	4.35%	(17,337)
Acct. 398 Misc. Equipment	(22,054)	2,251	(19,803)	5.56%	(1,101)
Total	(4,222,022)	781,589	(3,440,433)		(236,334)

Total Annualized Amortization-Acq. Discount	(3,779,889)
Test Year Amount per Books	(3,918,732)
Adjustment Required (FERC 406)	138,843

UNS Electric, Inc.
Emergency Bill Assistance Expense

Test Year Ended June 30, 2006

Docket No. E-04204A-06-0783
Schedule C-16
Page 1 of 1

Line No.	Description	Account	Amount	Reference
1	Increase to Emergency Bill Assistance Expense		$ 20,000	A

Notes and Source

A Testimony of Staff witnesses Ralph C. Smith and Julie McNeely-Kirwan

R14-2-102. Treatment of depreciation

A. The following definitions shall apply in this Section unless the context otherwise requires:

1. "Accumulated depreciation" means the summation of the annual provision for depreciation from the time that the asset is first devoted to public service.
2. "Cost of removal" means the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto.
3. "Depreciation" means an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life.
4. "Depreciation rate" means the percentage rate applied to the original cost of an asset to yield the annual provision for depreciation.
5. "Net salvage" means the salvage value of property retired less the cost of removal.
6. "Original cost" means the cost of property at the time it was first devoted to public service.
7. "Property retired" means assets which have been removed, sold, abandoned, destroyed, or which for any cause have been withdrawn from service and books of account.
8. "Salvage value" means the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts.
9. "Service life" means the period between the date an asset is first devoted to public service and the date of its retirement from service.

B. All public service corporations shall maintain adequate accounts and records related to depreciation practices, subject to the following:

1. Annual depreciation accruals shall be recorded.
2. A separate reserve for each account or functional account shall be maintained.
3. The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systemic manner over the estimated service life of such plant.
4. Public service corporations having less than $250,000 in annual revenue shall not be required to maintain depreciation records by separate accounts but shall make annual composite accruals to accumulated depreciation for total depreciable plant.

C. Requests for depreciation rate changes and methods for estimating depreciation rates shall be as follows:

1. If a public service corporation seeks a change in its depreciation rates, it shall submit a request for such as part of a rate application in accordance with the requirements of R14-2-103.
2. A public service corporation may propose any reasonable method for estimating service lives, salvage values, and cost of removal. The method shall be fully described in a request to change depreciation rates.
3. Data and analyses supporting the change shall be submitted, including engineering data and assessment of the impact and appropriateness of the change for ratemaking purposes.
4. Changed depreciation rates shall not become effective until the Commission authorizes such changes.

D. Upon the motion of any party or upon its own motion, the Commission may determine that good cause exists for granting a waiver from one or more of the requirements of this Section.

Historical Note

Former Section R14-2-102 repealed, former Section R14-2-127 renumbered as Section R14-2-102 without change effective March 2, 1982 (Supp. 82-2). Forward to the rule corrected as filed April 13, 1973 (Supp. 89-1). Section R14-2-102 repealed, new Section adopted effective April 9, 1992 (Supp. 92-2).

Power Supply Adjustment
Plan of Administration

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company ("APS") by the Commission on xxxxx, xx, 200x in Decision No. xxxxxxxx. This PSA replaces the Power Supply Adjustment mechanism approved in Decision No. 67744 ("the old PSA"). The PSA provides for the recovery of fuel and purchased power costs from January 1, 2007 onward.

The old PSA used historical, experienced costs to set a PSA rate, and then reconciled subsequent collections thereunder to actual costs, subject to a number of guidelines and limitations. By contrast, the PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This PSA also provides for a transition method for the refund or collection of balances accrued under the old PSA, prior to its replacement by this PSA. This PSA also provides a mechanism for mid-year rate adjustment in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

This POA describes the application of the PSA. It assumes that the old PSA continues to apply until the Commission decision regarding the adoption of this PSA during the first quarter of 2007.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year (each February 1 through January 31 period shall constitute a PSA Year) fuel and purchased power costs and those embedded in base rates.

2. The Historical Component, which tracks the differences between the PSA Year's actual fuel and purchased power costs and those recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PSA Year.
3. The Transition Component, which provides for:
   a. The refund or recovery of balances arising under the provisions of the old PSA, prior to its replacement by this PSA.
   b. The opportunity to seek a mid-year change in the PSA rate in cases where variances between recovery of fuel and purchased power costs under the combination of base rates and the Forward Component become so large as to warrant recovery, should the Commission first deem such an adjustment to be appropriate.
   c. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

The PSA Year begins on February 1 and ends on the ensuing January 31.[1] The first PSA Year in which the new PSA rate shall apply will begin on February 1, 2007 or such other date on which the Commission approves the adoption of this PSA. In any event, the first PSA Year will end on January 31, 2008. Succeeding PSA Years will begin on each February 1 thereafter.

On or before September 30 of each year, APS will submit a PSA Rate filing, which shall include a proposed calculation of the three components of the PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required. APS will supplement this filing with Historical Component and Transition Component filings on or before December 31 in order to replace estimated balances with actual balances, as explained below.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PSA Year that begins on February 1 and ends on the ensuing January 31. APS will submit, on or before September 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its fuel and purchased power costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecasted costs by the forecasted sales to produce the ¢/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This account will operate on a PSA Year basis (*i.e.*; February to January), and its

[1] The Commission decision approving this PSA may come after February 1, 2007, in which case the first PSA Year will be less than 12 months.

balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the Forward Component Tracking Account balance and the Historical Component Tracking Account balance is divided by the forecasted kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual September 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the current PSA Year). The APS filing shall use these balances to calculate a preliminary Historical Component for the coming PSA Year[2]. On or before December 31, APS will submit a supplemental filing that recalculates the preliminary Historical Component. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the September 30 filing.

The September 30 filing's use of estimated balances for September through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision prior to February 1. The December 31 updating will allow for the use of the most current balance information available prior to the time when a Commission decision is expected. In addition to the December 31 update filing, APS monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and Historical Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected Historical Component unit rate required for the next PSA Year.[3]

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component

[2] For example, the September 30, 2007 filing would include actual balances for February through August of 2007 and estimated balances for September 2007 through January 2008.

[3] This updating to replace estimated with actual information will allow for the Commission to use the latest available balance information in determining what Historical Component is appropriate to establish for the coming PSA Year.

Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

As of February 1, 2007, there will remain balances under the operation of the old PSA. This PSA does not make any change in the recoverability of such balances, but does apply the Transition Component as a method for recovering such balances as are already permitted for recovery under the old PSA and whose recovery the Commission may otherwise allow. The Transition Component will provide for the capturing and collection of those balances. This plan contemplates that pre-2007 balances already approved for recovery (but not already recovered) under the old PSA will be rolled into the Transition Component upon this PSA's effective date. The Commission may, however, choose to continue recovery of any approved 2005 and 2006 balances through a continuation of the old PSA, to the extent that the new PSA may not be approved at or near February 1, 2007, or to the extent that rate elements designed to recover such balances have been set for recovery periods that do not match a PSA Year. APS will continue to make the filings required under the old PSA for so long as is necessary to recover and reconcile any balances arising thereunder, to the extent that such balances have not been transferred for recovery through the Transition Component of this PSA. In either event, all collections of approved pre-2007 balances will be subject to reconciliation.

The pre-2007 charges already approved for recovery under the old PSA consist of the following:[4]

1. February 1, 2006 adjustor rate of $0.004 per kWh, which is expected to recover about $110 million of 2005 costs through January 31, 2007, after which it is expected to be replaced by an adjustor rate that will recover expected 2006 balances
2. May 1, 2006, surcharge of $0.000554 per kWh to recover $15 million of 2005 costs outside of 4 mil bandwidth that are not related to nuclear plant outages; and expected to be collected across a duration of 12 months
3. May 1, 2006, interim adjustor rate of $0.007 per kWh to recover certain 2006 costs as described in Decision No. 68685.

Any 2007 balances accruing under the old PSA before its replacement will be tracked during the first PSA Year, and their recovery shall be addressed in the calculation of the Transition Component applicable during the second PSA Year, which shall begin on February 1, 2008, except as follows. A Commission December 2006 decision extended the interim adjustor rate of $0.007 per kWh until new rates become effective following the order in the pending rate case docket. That recent Commission decision provides for the recovery of expected 2007 costs in excess of current base rates. It appears that this extension of the $0.007 per kWh interim adjustor rate may produce a negative balance (*i.e.*, an over collection of 2007 costs) by mid-year 2007. Therefore, if the Commission decides to use the new PSA's Transition Component in the first PSA year (ending January 31, 2008) to provide for the recovery of 2005 and 2006 balances, nothing in this plan shall preclude a determination by the Commission to include any 2007

[4] Depending upon the Commission's resolution of APS' pending rate case, Docket No. E-01345A-05-0816, APS may also be allowed to recover certain prudently incurred fuel and purchased power costs incurred as a result of certain Palo Verde outages.

balances accruing under this extended $0.007 per kWh interim adjustor rate in the calculation of the Transition Component to be effective in the PSA Year ending January 31, 2008.

In order to facilitate the orderly transition to a new PSA, APS should file by December 31, 2006[5] a calculation of the ¢/kWh unit rate required to collect costs included in the preceding list over the same estimate of 2007 sales used to calculate the Forward Component. This calculation shall comprise the Transition Component for the first PSA Year's PSA rate, should the Commission determine to allow their recovery through the new PSA. APS should also file by December 31, 2006 a calculation of the ¢/kWh unit rate(s) and duration(s) required to collect costs included in the preceding list by continuing the old PSA for the purpose of their collection. Should the Commission adopt the approach of continuing the old PSA for the limited purpose of collecting any 2005 or 2006 balances, the Transition Component shall be used to reconcile all affected balances, beginning with the First PSA Year following the termination of the duration established for the collection of any remaining 2005 and 2006 balance through continuation of the old PSA.

The Transition Component will also be used if necessary to address the need for any other reconciliations that may be required or appropriate under the old PSA. Following review, the Commission will determine the amount to be collected and the period over which it will be collected. The amount permitted to be collected shall be included in the Transition Component Balance. The Transition Component will provide the PSA element for the collection of the approved Transition Component Balance over the time period established by the Commission.

The preceding uses of the Transition Component deal with the transition from the old PSA to this PSA. The Transition Component will also be used as the method for incorporating any future, approved mid-year changes to the PSA rate. APS, Staff, or the Commission on its own motion retain the ability to request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between collections and costs under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate (¢/kWh) imposed as part of the Transition Component.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

[5] Staff acknowledges that the 2006 information would have to be addressed in the context of the pending rate case, Docket No. E-01345A-05-0816.

As it must do for the Historical Component filing, APS shall file on or before September 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through August and an estimate of the balances for September through January (the remaining five months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year. On or before December 31, APS will submit a supplemental filing to update the Transition Component calculation in the same manner as required for the Historical Component.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.*, Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate (as amended by the updated December 31 filing) shall go into effect. The PSA rate shall be applicable to APS' retail electric rate schedules (with the exception of Solar-1, Solar-2, SP-1, E-3, E-4, E-36, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first billing cycle in February unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. September 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before September 30 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming calendar year, with all inputs and assumptions being current as of that date for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[6]

b. December 31 Filing

APS shall by December 31 update the September 30 filing. This update shall replace estimated Forward Component Tracking Account balances, the Historical Component Tracking Account balances, and the Transition Component Tracking Account balances with actual balances and with more current estimates for those months (December and January) for which actual data are

[6] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

not available. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect on February 1.[7]

c. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

d. Review Process

The Commission Staff and interested parties shall have an opportunity to review the September 30 and December 31 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the September 30 calculations shall be filed within 45 days of the APS filing. Any objections to the December 31 calculations shall be filed within 15 days of the APS filing.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15.

Base Cost of Fuel and Purchased Power – An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in APS' most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.0XXXXX per kWh effective on XXX, XXXX.

Forward Component – An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecasted fuel and purchased power costs generally expressed as a rate per kWh less the Base Cost of Fuel and Purchased Power generally expressed as a rate per kWh embedded in APS' base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

[7] No reference in this plan to effectiveness in the absence of Commission action shall be interpreted as precluding the normal application of the balance reconciliation provisions generally established for the new PSA.

Forward Component Tracking Account – An account that records on a monthly basis APS' over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component – An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account – An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest; the balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI –Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load – Native load includes customer load in the APS control area for which APS has a generation service obligation and PacifiCorp Supplemental Sales.

PacifiCorp Supplemental Sales – The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990, which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Old PSA – The Power Supply Adjustment mechanism approved in Decision No. 67744 to track changes in the APS cost of obtaining fuel and purchased power.

This PSA – The Power Supply Adjustment mechanism approved by the Commission in Decision No. xxxxx, which is a combination of three rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced. This PSA also provides for the transition from the prior PSA to this PSA, allows for special Commission consideration of extreme volatility in costs or recovery by means of a mid-year rate correction, and provides for a reconciliation between actual and estimated costs of the last two months of estimated costs used in Historical Component calculations.

PSA Year – A consecutive 12-month period generally beginning each February 1.

PSA Year One – A period beginning on the date determined by the Commission in Decision No. xxxxx and ending on January 31, 2008.

Preference Power – Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

System Book Fuel and Purchased Power Costs – The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs are included; broker fees are excluded.

System Book Off-System Sales Revenue – The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale – The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component – An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for: (a) the transition between the prior PSA and current PSA, and (b) significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account – An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) – Amounts payable to others for the transmission of APS' electricity over transmission facilities owned by others.

7. Calculations

a. Schedule 1. PSA Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component Rate from Schedule 2, Line 8.
2. On Line 2, enter the Historical Component Rate from Schedule 4, Line 5.
3. On Line 4, enter the Transition Component Rate for the Commission approved prior PSA transition refund/collection balance from Schedule 6, Line 3.
4. On Line 5, enter the Transition Component Rate for any Commission approved Mid-Period Transition refund/collection balance from Schedule 6, Line 6.

5. On Line 6, enter the Transition Component Rate for any other Commission approved Transition adjustment refund/collection balance from Schedule 6, line 9.
6. On Line 7, enter the Tracking Account Transition Component Rate for any Commission approved refund/collection Tracking Account balance from Schedule 6, Line 20.
7. On Line 8, enter the sum of Lines 4 through 7 to calculate total Transition Component Rate.
8. On Line 9, enter the sum of Lines 1, 2, and 8 to calculate the total PSA Rate.
9. Calculate the Increase/(Decrease) in rates and % Change by respective lines: Proposed Rates Less Current Rates equals Increase/(Decrease) with result divided by Current Rate to determine % of Increase/(Decrease).

Reflect notes as appropriate.

b. Schedule 2. PSA Forward Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On line 1, enter the Projected Fuel and Purchased Power Costs for the coming year.
2. On Line 2, enter the Projected Off-System Sales Revenue (entered as a negative value) for the coming year.
3. On Line 3, enter the PSA Adjustments to Fuel and Purchased Power Costs for the coming year.
4. On Line 4, enter the sum of Lines 1 through 3 to arrive at the Net Fuel and Purchased Power Costs.
5. On Line 5, enter the Projected Native Load Sales (MWh), excluding the E-3, E-4, E-36 sales for the coming year.
6. On Line 6, enter the derivation of the Net Fuel and Purchased Power Costs divided by the Projected Native Load Sales to arrive at the Projected Average Net Fuel Cost per kWh.
7. On Line 7, enter the Authorized Base Cost of Fuel and Purchased Power Rate per kWh.
8. On Line 8, enter the sum of Line 6 less Line 7 to arrive at the Forward Component rate per kWh; and then carry forward resultant value to Schedule 1, Line 1.

Reflect notes as appropriate.

c. Schedule 3. Forward Component Tracking Account

Enter the appropriate: effective dates for the PSA ***Prior*** Forward Component being tracked; year for the column headed "Cycle Billing Month"; and Base Rate and Forward Component in columns ***h*** and ***i***. On lines 1 through 12 under the Cycle Billing Month, January through December for each respective column complete the following:

1. On Lines 1 to 12, enter the monthly PSA Retail Energy Sales (MWh) and the monthly Wholesale Native Load Energy Sales in columns ***a*** and ***b***, respectively; the sum which equals the Total Native Load Energy Sales; column ***c***. Currently, Wholesale Native Load Energy Sales include Traditional Sales-for-Resale and PacifiCorp Supplemental Sales.

2. On Lines 1 to 12, enter the monthly System Book Fuel and Purchased Power Costs and the monthly System Book Off-System Sales Revenue in columns ***d*** and ***e***, respectively; the sum of column ***d*** minus ***e*** equals the monthly Net Native Load Power Supply Costs in column ***f***. The off-system sales margin is embedded in the Net Native Load Power Supply Cost. The costs associated with the off-system sales are included in the System Book Fuel and Purchased Power Costs. When the System Book Off-System Sales Revenue is subtracted from the System Book Fuel and Purchased Power Costs, the difference between the off-system sales costs and revenue ends up in the Net Native Load Power Supply Cost. That difference is the off-system sales margin. A list of the items included in the PSA sales and costs described above will be included in the PSA reporting schedules filed with the Commission each month.
3. On Lines 1 to 12, calculate the PSA Retail Power Supply Costs, column ***g*** by dividing the PSA Retail Energy Sales in column ***a*** by the Total Native Load Energy Sales in column ***c***, then multiply the product by the Net Native Load Power Supply Costs in column ***f***. Directly-assigned power supply costs and related energy sales from applicable special contract customers, Schedule E-36 customers, and customers returning to Standard Offer service from competitive generation subject to Returning Customer Direct Access Charge ("RCDAC") treatment will be deducted prior to the above calculations.
4. On Lines 1 to 12, calculate the amount recovered via the Commission approved embedded base fuel and purchased power rate by multiplying the Retail Energy Sales in column ***a*** by the Commission approved Base Cost of Fuel and Purchased Power rate entered in the above column heading the result which is entered in column ***h***.
5. On Lines 1 to 12, calculate the amount recovered via the Forward Component rate by multiplying said rate by the Retail Energy Sales in column ***a***, the result which is entered in column ***i***.
6. On lines 1 to 12, calculate the respective level of (Over)/Under Collection in column ***j*** by subtracting the Base Rate Power Supply Recovery and the Forward Component Recovery from the PSA Retail Power Supply Costs, columns ***g*** and ***h***, respectively.

An interest rate, based on the one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15, is applied each month to the previous month's Tracking Account Balance. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

The (Over)/Under Collection, the Interest and the prior month's Tracking Account Balance produce the current month's balance.

d. Schedule 4. PSA Historical Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA-2 columns and then complete the following in each respective column:

1. On Line 1, enter the Forward Component Tracking Account Balance from Schedule 3, L13, column ***i***.

2. On Line 2, enter the Historical Component Tracking Account Balance from Schedule 5, Line 8.
3. On Line 3, enter the sum of Lines 1, and 2 to arrive at the Total (Refundable)/Collection Amount Balance.
4. On Line 4, enter the respective Projected Energy Sales without E-3, E-4 and E-36 MWh.
5. On Line 5, enter the Applicable Historical Component rate by dividing Line 3 by Line 4.

Reflect notes as appropriate.

e. Schedule 5. Historical Component Tracking Account

Enter the appropriate: effective dates for the PSA ***Prior*** Historical Component being tracked.

On Line 8, for January and Line 1 for February, enter the Historical Component balance as of February 1, 20XX. On Line 2, (Prior period PSA Historical Component Calculation From Schedule 4, L4) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Historical Component rate application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Adjusted Historical Component Beginning Balance as of February 1, 20XX.

Each month, the Applicable Historical Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Historical Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Reflect notes as appropriate.

f. Schedule 6. PSA Transition Component Rate Calculation

Enter the appropriate effective periods for the Current and Proposed PSA columns and then complete the following in each respective column:

1. On Line 1, enter the Prior PSA Transition Commission Approved (Refundable)/Collection Amount.
2. On Line 2, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
3. On Line 3, calculate the Prior PSA Transition Component (Refundable)/Collection Rate by dividing Line 1 by Line 2.
4. On Line 4, enter the PSA Mid-Period Transition Commission Approved (Refundable)/Collection Amount, if any.
5. On Line 5, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
6. On Line 6, calculate the Mid-Period Transition Component (Refundable)/Collection Rate by dividing Line 4 by Line 5.

7. On Line 7, enter Any Other Transition Commission Approved (Refundable)/Collection Amount, if any.
8. On Line 8, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
9. On Line 9, calculate the Any Other Transition Component (Refundable)/Collection Rate by dividing Line 7 by Line 8.
10. On Line 10, enter the sum of Lines 3, 6, and 9 to arrive at the total Transition Component Rate (Non-Tracking Account Items).
11. On Line 11, enter the Prior PSA Transition Tracking Account Balance from Schedule 7a, Line 8.
12. On Line 12, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
13. On Line 13, calculate the Prior PSA Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 11 by Line 12.
14. On Line 14, enter the Mid-Period PSA Transition Tracking Account Balance from Schedule 7b, Line 8, if any.
15. On Line 15, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
16. On Line 16, calculate the Mid-Period Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 14 by Line 15.
17. On Line 17, enter Any Other PSA Transition Tracking Account Balance from Schedule 7X, Line 8, if any.
18. On Line 18, enter the Projected Energy Sales without E-3, E-4, and E-36 MWh.
19. On Line 19, calculate the Any Other Tracking Account Transition Component (Refundable)/Collection Rate by dividing Line 17 by Line 18.
20. On Line 20, calculate the total Tracking Account Transition Component by adding Lines 13, 16, and 19.
21. On Line 21, calculate the total Transition Component Rate by adding Lines 10 and 20.

Reflect notes as appropriate.

g. Schedule 7a. Transition Component Tracking Account "Old PSA"

Enter the appropriate: effective dates for the PSA ***Prior*** Transition Component to be tracked.

On Line 8, for January and Line 1 for February, enter the Transition Component, Old PSA balance as of February 1, 20XX. On Line 2, (Prior period PSA Transition Component Calculation From Schedule 6, L1) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Transition Component, Old PSA application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Transition Component Adjusted Beginning Balance as of February 1, 20XX.

Each month, the Applicable Transition Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Transition Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Any subsequent balance produced must be approved by the Commission for later inclusion in the next Transition Component Calculation, if any, at Schedule 6, Line 11.

Reflect notes as appropriate.

h. Schedule 7b. Mid-Period Transition Tracking Account

Enter the appropriate: effective dates for the PSA ***Mid-Period*** Transition Component to be tracked.

On Line 8, for January and Line 1 for February, enter the Transition Component, PSA Mid-Period balance as of February 1, 20XX. On Line 2, (Prior period PSA Transition Component Calculation From Schedule 6, L4) for February enter any true-up for the use of prior period estimates, i.e., prior estimated December and January Transition Component rate application revenues to subsequent actual data, the sum of Lines 1 and 2, to reflect the Adjusted Transition Component Beginning Balance as of February 1, 20XX.

Each month, the Applicable Transition Component rate is multiplied by the Retail Energy Sales to calculate the revenue received from the Applicable Transition Component rate. The revenue is subtracted from the Adjusted Beginning Balance.

Interest is applied monthly based on the effective one-year Nominal Treasury Constant Maturities rate that is contained in the Federal Reserve Statistical Release, H-15, or its successor publication. The interest rate is adjusted annually on the first business day of the calendar year in the same manner as the APS customer deposit rate.

Any subsequent balance produced must be approved by the Commission for later inclusion in the next Transition Component Calculation, if any, at Schedule 6, Line 14.

Reflect notes as appropriate.

i. Schedule 7X. (Enter Description) Transition Tracking Account

Follow similar procedures discussed in g and h above, for any other Transition Tracking Accounts.

8. Compliance Reports

APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PSA calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total off-system sales revenues.
    g. System losses in MW and MWh.
    h. Monthly maximum retail demand in MW.

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
   1. Net generation, in MWh per month, and 12 months cumulatively.
   2. Average heat rate, both monthly and 12-month average.
   3. Equivalent forced-outage rate, both monthly and 12-month average.
   4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
   5. Total fuel costs per month.
   6. The fuel cost per kWh per month.

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
   1. The quantity purchased in MWh.
   2. The demand purchased in MW to the extent specified in the contract.
   3. The total cost for demand to the extent specified in the contract.
   4. The total cost of energy.

C. Information on off-system sales shall include the following items:
   1. An itemization of off-system sales margins per buyer.
   2. Details on negative off-system sales margins.

D. Fuel purchase information shall include the following items:

1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (Over)/under-collected amounts.
2. A summary of unplanned outage costs by resource type.
3. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund, if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs are excluded from the PSA.

Attachment RCS-5

Copies of UNS Electric's Responses to Data Requests

Referenced in the Direct Testimony and Schedules of

Ralph C. Smith

Data Request No.	Subject	Confidential	Pages
STF 3.87	Fair Value Rate Base	No	2-3
STF 15.4	Adjust CWIP for Plant in Service by End of Test Year and Customer Advances	No	4-11
STF 3.60	Accumulated Deferred Income Taxes	Yes	12-18
STF 11.24	Fleet Fuel Expense	No	19-21
STF 3.101	Injuries & Damages Expense	No	22
STF 11.16	Worker's Compensation Expense	No	23
STF 3.102	Injuries & Damages Expense	No	24
STF 11.15	Injuries & Damages Expense	No	25-28
STF 3.83	Incentive Compensation and SERP Expense	Yes [1]	29-49
STF 11.5	Incentive Compensation Expense (Issued in UNS Gas - Docket No. G-04204A-06-0483	No	50-51
STF 10.11	Stock Based Compensation	No	52-53
STF 3.72	EEI and Other Membership Dues	No	54-56
MM DR 2.27	Other Membership Dues	No	57
STF 3.55	Other Membership Dues	No	58-60
STF 3.39 & STF 11.8	Depreciation Expense	No	61-72
STF 3.70, STF 10.4, STF 10.5, STF 10.6, STF 11.10 and STF 15.1	SES Affiliated Charges	No	73-79
STF 3.19 & STF 3.30	Depreciation Rates	No	80-81
STF 11.2	Black Mountain Generating Station	No	82
	Total Pages Including this Page		82

[1] Only the attachments to the response for subparts d, e and f on pages 35-49 are confidential.

Pages 12-18 and 35-49 containing information designated as "Confidential" by the Company have been redacted from Attachment RCS-5 and have been filed under seal in a separate document.

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007**

STF 3.87 Fair value rate base.

a. As of August 11, 2003, the date of acquisition, would the fair value of the assets acquired from Citizens be equal to the purchase price paid by UniSource? If not, explain fully why not.

b. Was the acquisition of the electric utility the result of an arm's length transaction between a willing and informed buyer and a willing and informed seller? If not, explain fully why not.

c. In deciding how much to pay for the electric utility, please describe how and to what extent UniSource make use of reconstructed cost new (RCN) information, reconstructed cost new depreciated (RCND) information, Handy-Whitman Index information, Marshall Index information, and/or Bureau of Labor Statistics index information. To the extent that UniSource did not use such information as the basis for determining the purchase price to pay for the electric utility, please explain fully why not.

d. Why does UniSource believe it was able to acquire the electric utility at a price less than original cost depreciated book value? Explain fully.

RESPONSE:

a. Yes.

b. Yes.

c. The above-referenced information was given little or no weight in deciding what price UniSource Energy would be willing to pay for the electric utility properties owned by Citizens. Instead, the purchase price was more heavily influenced by the physical condition of the utility properties, the ability to recover purchased power costs, prevailing rates for distribution services, financing costs, and the expected growth in sales, expenses and capital expenditures.

d. There are two primary reasons. First, the retail rates charged for distribution services provided an inadequate rate of return on the original cost depreciated book value of utility property. Second, Citizens appeared to be a highly motivated seller, as witnessed by its decision to write-off a substantial balance of deferred purchased power costs.

UNS ELECTRIC, INC.'S RESPONSES TO STAFF'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 May 17, 2007

RESPONDENT: Kent Grant

WITNESS: Kent Grant

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FIFTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 26, 2007**

STF 15.4 Customer Advances. Please refer to the response to STF 10.20.

a. Are the $12,045,607 Customer Advances as of June 2006 in FERC Account 252 reflected anywhere on Schedule B-1, Summary of Original Cost and RCND Rate Base? If so, where are the Customer Advances reflected on that schedule and in what amount.

b. Are the $12,045,607 Customer Advances as of June 2006 in FERC Account 252 reflected anywhere on Schedule B-2, Pro Forma Adjustments to Original Cost Rate Base? If so, where are the Customer Advances reflected on that schedule and in what amount.

c. Has UNS Electric included any amounts of Accumulated Deferred Income Taxes (ADIT) in rate base related to the amount Customer Advances as of June 2006? If so, please identify all ADIT amounts in rate base related to Customer Advances, and clearly show the relationship between the amount of Customer Advances that the Company has reflected as a deduction to rate base and the amount of ADIT that the Company has included in rate base related to Customer Advances.

d. As of 6/30/06, had UNS Electric received any Customer Advance relating to the Tubac Golf Resort Overhead to Underground Conversion (Task CE64023)? If so, please identify the Customer Advance related to this project that was recorded on UNS Electric's books as of 6/30/06.

e. Subsequent to 6/30/06, has UNS Electric received any Customer Advance relating to the Tubac Golf Resort Overhead to Underground Conversion (Task CE64023)? If so, please identify the amount of Customer Advances related to this project that was recorded on UNS Electric's books subsequent to 6/30/06.

UNS ELECTRIC, INC.'S RESPONSES TO STAFF'S FIFTEENTH SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 June 26, 2007

f. As of 6/30/06, had UNS Electric received any Customer Advance relating to the Rhodes Homes line extension project (Task 8009729)? If so, please identify the Customer Advance related to this project that was recorded on UNS Electric's books as of 6/30/06.

g. Subsequent to 6/30/06, has UNS Electric received any Customer Advance relating to the relating to the Rhodes Homes line extension project (Task 8009729)? If so, please identify the amount of Customer Advances related to this project that was recorded on UNS Electric's books subsequent to 6/30/06.

h. Please show in detail how the amounts of Customer Advances listed in response to c, d, e and f were determined.

i. Subsequent to 6/30/06, has UNS Electric refunded any Customer Advances relating to the Rhodes Homes line extension project (Task 8009729) or to the Tubac Golf Resort Overhead to Underground Conversion (Task CE64023)? If so, please identify the date and refund amounts for any and all refunds related to each project.

RESPONSE:

a. STF 10.20 a. has been revised. The revised table reflects a June 30, 2006 Customer Advance balance of $8,692,444. This is the balance that is reflected on Schedule B-1, Summary of Original Cost and RCND Rate Base.

b. STF 10.20 a. has been revised. The revised table reflects a June 30, 2006 Customer Advance balance of $8,692,444. This is the balance that is reflected on Schedule B-2, Pro Forma Adjustments to Original Cost Rate Base.

c. Consistent with Commission Decision No. 55774, issued in October 1987, the rate base element Accumulated Deferred Income Taxes includes the Deferred Tax Asset associated with Contributions and Advances in Aid of Construction, computed at the average test year amount. For a detailed itemization of Accumulated Deferred Income Taxes, please refer to the response to STF 3.60.

UNS ELECTRIC, INC.'S RESPONSES TO STAFF'S FIFTEENTH SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 June 26, 2007

d. No. This customer requested work was paid 100% by the customer as a Contribution in Aid of Construction.

e. Please see the response to d. above.

f. Yes. As of June 30, 2006 UNS Electric had received $360,117.09 for this project.

g. No.

h. For subpart c. above, ADIT for customer advances is computed by taking the average of the total post acquisition advance liabilities as of June 30, 2005 and June 30, 2006. Pre Acquisition advances have no impact on ADIT. Please see STF 15.4 (h) (Cust. Adv. ADIT), Bates No. UNSE(0783)09893, on the enclosed CD for the calculation of subpart c.

Subparts (d) and (e) are not applicable.

Please see 15.4 (h) (Line Ext. Cost Est.), Bates No. UNSE(0783)09894, on the enclosed CD for the detailed Line Extension Cost Estimate, a letter requesting an engineering advance and the Letter of Agreement to Rhodes Homes.

i. No refunds have been made to Rhodes Homes (Task 8009729). Tubac Golf Resort (Task CE 64023) would not be eligible for a refund.

RESPONDENTS: Sandie Becker (a and b)
Carl Dabelstein (c)
Tom Hoyt (d and e)
Teri Rice (f, g, h and i)

WITNESSES: Karen Kissinger (a, b and c)
Thomas Ferry (d, e, f, g, h and i)

LINE EXTENSION COST ESTIMATE

MOHAVE ELECTRIC - KINGMAN, ARIZONA

Customer Rhodes Homes AZ/GV Well #1 Prepared By GKELLER
8009729 Date 03/02/06

PHASE	CONSTRUCTION UNIT	UNIT COST	# REQD.	EXTENDED
	TANGENT			0.00
	ANGLE			0.00
	DEAD END			0.00
	DOUBLE DEAD END			0.00
	SLACK SPAN			0.00
	INSET			0.00
	SLEEVE THROUGH/TAKE-OFF			0.00
	DOWN GUY			0.00
	OVERHEAD GUY			0.00
	ANCHOR			0.00
	LINE EXT WELL #2	34868	1	34868.00
	LINE DAMPNERS	23.88	360	8596.80
	OTHER	175,160.87	1	175160.87

LABOR

	(ADDITIONAL FOREMAN/JOURNEYMAN)			
Line Crew	$171.03 per hr.	x	300.00 hrs.	= $51,309.00
Digger Crew	$35.80 per hr.	x	100.00 hrs.	= $3,580.00

Total Material	$218,625.67
Total labor	+ $54,889.00
Total Direct (Material & Labor)	$273,514.67

Overhead	50.800% x labor		$27,883.61
Engineering	2.000% x (T.D. +O.H.)		$6,027.97
Interest	0.310% x .5 x (T.D. + ENG. + O.H.	3 Mos.	$1,906.04
AR-13	0.240% x (T.D. + ENG. +O.H. + IN	3 Mos.	$1,484.79
Outside Engineering/Staking Fees: (Stanley Consultants)			$49,300.00
Total Cost			$360,117.09

2498 Airway Avenue
P.O. Box 3099
Kingman, Arizona [illegible]
928 681 [illegible]

JniSource SERVICES

November 29, 2005

Mr. Kirk Brynjulson
Mr. James Rhodes
Rhodes Homes Arizona
2215 Hualapai Mountain Road, Suite H
Kingman, Arizona 86401

RE: Electric Service - Preparation Cost
4621 West Dora Drive, Golden Valley Well #1

Dear Sirs:

This letter is in reference to your inquiry regarding the cost of extending three-phase overhead electric distribution lines to 4621 West Dora Drive, Parcel 306-63-009, situate in Section 34, Township 21 North, Range 18 West, Gila and Salt River Meridian, Mohave County, Arizona.

UNS Electric, Inc. would need to construct a three-phase overhead distribution line approximately 23,760 feet to reach your service area. A rough estimate of the construction cost is determined to be approximately $300,000.00. You will be required to advance the total cost of construction prior to the start of construction of the electric facilities.

If you request a detailed plan and cost estimate, you will be required to deposit with UNS Electric, Inc. an amount of $30,000.00 to cover the estimated cost of preparation. If you authorize UNS Electric, Inc. to proceed with construction of the extension within twelve months after receiving the extension agreements, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be non-refundable.

If the proposed route will require UNS Electric, Inc. to obtain a right of way through BLM Land/State of Arizona Trust Land, prior experience indicates that it could take several months to acquire this permit.

Electric service will be provided in accordance with UNS Electric, Inc.'s Rules and Regulations on file with, and approved by, the Arizona Corporation Commission.

If you are in agreement to the above, please remit to UNS Electric, Inc. the amount of $30,000.00. Please feel free to contact the engineering department at 928-681-8929 if you have any additional questions.

Sincerely,

Gene M. Keller

Gene M. Keller
Engineering Technician III

2498 Airway Avenue
P.O. Box 3099
Kingman, Arizona 86402-3099
928.681.4100

.iiSource
SERVICES

March 2, 2006

Mr. Kirk Brynjulson
Mr. James Rhodes
Rhodes Homes Arizona
2215 Hualapai Mountain Road, Suite H
Kingman, AZ 86401

Dear Messrs. Brynjulson and Rhodes:

This Letter of Agreement is entered into between UNS Electric, Inc., an Arizona Corporation, hereinafter referred to as "Company", and Rhodes Homes Arizona, hereinafter referred to as "Customer". This Letter of Agreement covers the conditions under which Company will extend overhead electric service to 4621 West Dora Drive, Parcel 1A, Section 34, and to 1509 South Amado Road, Lot 105, Section 37, both in Township 21 North, Range 18 West, Gila and Salt River Meridian, Mohave County, Arizona. This extension will be made under the provisions of Company's Extension Rules, Section II, D.1.c. and D.3., enclosed.

Company will install 25,892 feet of three-phase 20.8-kV overhead primary distribution line and provide 2400-volt electric service to Customer's water wells.

The estimated construction cost of primary distribution facilities is $360,117.09. The extension will be made under the provisions of Section II, D.3., Economic Feasibility Basis. Therefore, upon signing this Letter of Agreement, Customer will pay to Company $280,817.09 ($360,117.09 total Customer advance less $79,300.00 payment received as a preliminary engineering advance).

Customer's advance of $360,117.09 is refundable, without interest, under the provision of Section II, D.1.c. Company will determine the refund based on actual annual revenues received from service to the two wells. An analysis will be conducted annually in accordance with Section II, D.1.c. The obligation of Company to make refunds to Customer shall terminate five (5) years after the date of this Letter of Agreement. Any refund will be made to Rhodes Homes Arizona.

Customer will furnish, or cause to be furnished, at no cost to Company, easements perpetual in nature necessary to meet service requirements. Any annual expenses associated with said easements shall be paid in advance by Customer for the term of this Letter of Agreement.

Enclosed with this Letter of Agreement is the current electric rate schedule for the type of service for which you will be billed.

Company's estimated starting date for construction will commence within 30 days of execution of the Letter of Agreement and receipt of all necessary permits and easements.

This Letter of Agreement supersedes any and all other agreements or Letter of Understanding that may have come before Company in connection with the matters herein contained. Any amendment, to be effective, must be made in writing.

UNS ELECTRIC, INC.

By: Bill DeJulio 3/16/06
Bill De Julio

Its: Transmission and Distribution Manager

ACCEPTED

By:

Date:

BD:gk 8009729
Enclosures: Extension Rule, Section II, D.1.c. and D. 3.
Rate Schedule

UNS Electric, Inc.
Customer Advances ADIT
Test Year Ended 6/30/2006

UNS Electric, Inc. Customer Advances Company: 033 Number, Period Name: JUN-05, JUN-06, Currency Code: USD, Natural Account: 28300, A$Acct$UNS_GL_SubAccount Parameter 1: 4040, 4041, 4043, 4044

A$Acct$Ul Acct$UNS_GL_Account:28300

Period	Suba/c Description	Ending Balance	Activity	
DEC-03	Cust Adv Construct-Post Acquisition*	(509,306)	(509,306)	**B**
DEC-04	Cust Adv Construct-Post Acquisition*	(1,696,002)	(1,186,696)	**C**
JUN-05	Cust Adv Construct-Post Acquisition	(3,264,012)	(1,568,010)	**D**
DEC-05	Cust Adv Construct-Post Acquisition*	(6,447,437)	(3,183,425)	**D**
JUN-06	Cust Adv Construct-Post Acquisition	(8,704,867)	(2,257,430)	**E**
			(8,704,867)	

Source> G/L Discoverer Query

Average Balance (6/30/2005 & 6/30/2006)	(5,984,440)	
Combined Federal & State Rate	38.60%	
Total Deferred Tax Asset	**2,309,874**	**A**

*These amounts are not considered in computing the average advance balance. It is presented here for the computations @ F1-F2.

THE COMPANY'S RESPONSE AND ATTACHMENTS TO STAFF DATA REQUEST STF 3.60 CONTAIN INFORMATION DESIGNATED AS "CONFIDENTIAL" BY THE COMPANY AND HAS BEEN REDACTED FROM THIS DOCUMENT, ATTACHMENT RCS-5. THE CONFIDENTIAL PAGES (12-18) ARE PROVIDED UNDER SEAL IN A SEPARATE DOCUMENT.

**UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
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June 14, 2007**

STF 11.24 Fleet Fuel Expense.

a. Refer to the workpapers used to calculate UNSE's Fleet Fuel Expense adjustment, specifically, the workpaper indicated by Bates number UNSE(0783)02108. Please provide similar data in the format shown on the referenced workpaper for the period September 2006 to date.

b. Has the Company's fleet fuel expense in 2006 or 2007 been impacted by any refinery outages? If so, please identify, quantify and explain the refinery outages and the related impacts on fleet fuel costs.

RESPONSE: Please find below a table in a similar format for September, 2006 to date for fleet fuel expense for UNS Electric.

**UNS Electric, Inc.
Fleet Fuel Expense - Invoices
September, 2006 - Current**

Wright Express Invoices:

Invoice Date	Gallons	Fuel Cost	Month	Cost/Gallon
10/9/2006	7,678	$21,262.37	Sep-06	$2.77
11/7/2006	8,163	$20,690.44	Oct-06	$2.53
12/6/2006	5,878	$15,380.32	Nov-06	$2.62
1/6/2007	5,432	$14,316.33	Dec-06	$2.64
2/7/2007	6,283	$16,187.27	Jan-07	$2.58
3/7/2007	5,808	$14,937.11	Feb-07	$2.57
4/6/2007	6,503	$18,338.70	Mar-07	$2.82
5/6/2007	6,144	$18,354.94	Apr-07	$2.99
	51,891	$139,467.48		$2.69

Non Wright Express Invoices:

Kingman Gascard

10/5/2006	5,306	$14,208.66	Sep-06	$2.68
10/20/2006	4,578	$11,687.15	Sep-06	$2.55
11/5/2006	4,730	$11,880.83	Oct-06	$2.51
11/20/2006	5,079	$13,089.11	Oct-06	$2.58
12/5/2006	4,055	$10,891.93	Nov-06	$2.69
12/20/2006	6,373	$17,250.81	Nov-06	$2.71
1/5/2007	4,364	$13,746.23	Dec-06	$3.15

UNS ELECTRIC, INC.'s RESPONSES TO STAFF'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 June 14, 2007

UNS Electric, Inc.
Fleet Fuel Expense - Invoices
September, 2006 - Current

1/20/2007	4,951	$10,489.23	Dec-06	$2.12
2/5/2007	5,361	$13,260.98	Jan-07	$2.47
2/20/2007	6,249	$16,235.41	Jan-07	$2.60
3/5/2007	3,387	$9,181.32	Feb-07	$2.71
3/20/2007	4,148	$11,538.48	Feb-07	$2.78
4/5/2007	5,187	$14,657.28	Mar-07	$2.83
4/27/2007	4,371	$13,036.70	Mar-07	$2.98
5/5/2007	3,745	$11,460.83	Apr-07	$3.06
	71,885	$192,614.95		$2.68
Parker Oil				
2/28/2007	1,103	$2,789.54	Jan-07	$2.53
3/16/2007	974	$2,521.62	Feb-07	$2.59
3/31/2007	555	$1,445.36	Feb-07	$2.60
4/1/2007	2,064	$6,030.15	Mar-07	$2.92
4/16/2007	835	$2,565.84	Mar-07	$3.07
4/30/2007	1,051	$3,250.72	Mar-07	$3.09
5/16/2007	1,192	$3,700.57	Apr-07	$3.10
	7,775	$22,303.80		
Texmo Oil Company				
9/6/2006	430	$1,364.23	Sep-06	$3.17
9/7/2006	420	$1,330.63	Sep-06	$3.17
9/11/2006	561	$1,672.00	Sep-06	$2.98
9/12/2006	185	$566.54	Sep-06	$3.06
9/13/2006	345	$1,084.39	Sep-06	$3.14
	1,941	$6,017.79		
Total Fuel Cost	133,491	$360,404		$2.70

The table was derived by pulling invoices from the vendors and summarizing.

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b. The Company does not receive information from our fuel vendors regarding oil refinery outages and the possible impact outages may have had on fleet fuel expense.

RESPONDENT: Marian Bryant and Michael Daranyi

WITNESS: Dallas Dukes

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STF 3.101 Injuries and Damages. State the amount of injuries and damages expense for each of the last three years, and for the test year.

RESPONSE: The injuries and damages expense in FERC 925 is as follows:

January 2004 - December 2004	$352,589
January 2005 - December 2005	$356,992
July 2005 - June 2006 (Test Year)	$562,403
January 2006 - December 2006	$500,440

RESPONDENT: Janet Zaidenberg-Schrum

WITNESS: Dallas Dukes

**UNS ELECTRIC, INC.'s RESPONSES TO
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STF 11.16 Insurance expense. Refer to the response to STF 3.102.

a. Explain fully why the Worker's Compensation Expense in the test year of $177,086 is so much higher than in 2004, 2005 and 2006.

b. Were any large or unusual monthly amounts recorded by UNS Electric for Worker's Compensation in the test year? If so, please identify and explain each such amount.

c. Why are the expense amounts for "Life, ST/LT Disability and ADD" negative for 2005 and for 2006? Explain fully. Please identify and explain the credit entries to these accounts that resulted in the negative expense amounts in each year.

d. Why are the expense amounts for "Life, ST/LT Disability and ADD" positive for the test year ending 6/30/06?

RESPONSE: a. UNS Electric is self-funded for worker's compensation claims up to $500k per claim. Worker's compensation expense consists of several items including: claims paid, claims administration fee paid to our third party administrator, excess worker's compensation premiums, quarterly reserve adjustments, and worker's compensation allocations out to capital projects. The quarterly reserve adjustment is based upon a Standard Loss Report provided by the administrator and designed to estimate probable future payments based on current information about known claims.

Expense Description	Test Year	2004	2005	2006
Claims Paid	58,231	47,737	25,994	81,058
Claims Admin. Fee	47,012	44,875	47,012	23,506
Quarterly Reserve Adj	63,252	41,686	(19,286)	20,275
Excess WC Prem.	11,634	11,941	689	10,945
Allocations to Capital	(1,548)	(16,785)	(10,241)	(24,894)
WC Refunds	(1,496)	0	0	(17,021)
Total	177,085	129,454	44,168	93,869
Worker's compensation premium charged to TEP	12,943		12,943	
Adjusted Total	190,028		57,111	

The above table reflects higher claims and reserve adjustments in the test year compared to 2004 and 2005. This is just a timing issue of when claims come through, which then is a basis for the reserve adjustment. The worker's compensation premium for 2005

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STF 3.102 Insurance Expense. Itemize each component of insurance expense included in the test year, and provide comparative information for calendar 2004, 2005 and 2006. Indicate the accounts and amounts in which each item of insurance expense is recorded.

RESPONSE:

Description	GL Account	Test Year	2004	2005	2006
Property	56040	65,598	78,770	64,630	68,458
Medical, Dental, and Vision	70520	848,198	994,265	771,405	1,016,463
Life, ST/LT Disability and ADD	70530	4,188	13,647	(1,376)	(4,425)
Officer's & Director's	78000	120,072	22,032	88,605	130,330
General Liability	78010	203,528	169,605	180,052	202,093
Injuries and Damages	78100	(7,825)	(1,229)	0	10,164
Worker's Compensation	78040, 50250	177,086	129,454	44,169	93,870

RESPONDENT: Sandie Becker

WITNESS: Karen Kissinger

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STF 11.15 Insurance expense. Refer to the response to STF 3.102.

a. Explain fully and in detail why Officers and Directors insurance has increased from $22,032 in 2004 to $88,605 in 2005 to $130,330 in 2006.

b. Provide a complete copy of the Officers and Directors insurance policy invoices for 2004 through 2006.

c. Have there been any lawsuits filed against UNS Electric or affiliate company Officers and Directors since the acquisition of the utility operation from Citizens? If so, please identify and describe all such lawsuits.

d. Were there any changes in coverage in Officers and Directors insurance from 2004 through 2006? If so, please identify and describe all such changes in coverages.

e. Were there any changes in the allocations to UNS Electric of Officers and Directors insurance from 2004 through 2006? If so, please identify, quantify and describe all such changes.

RESPONSE:

a. The increase in Officers and Directors insurance was due to how the expenses were allocated and also due to changes in coverage. Please see STF11.15 (a, d & e) on the enclosed CD for details. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

b. Please see STF 11.15 (b), Bates Nos. UNSE(0783)09352 to UNSE(0783)09364, on the enclosed CD for scanned invoices.

c. There have been no lawsuits filed against UNS Electric's Officers and Directors since the acquisition of the utility operation from Citizens.

d. Please see STF 11.15 (a, d & e) on the enclosed CD. This schedule shows how the invoices in response STF 11/15 b. are allocated.

The above mentioned schedule reflects the coverage limits by policy. The basic policies have remained substantially the same over the years. Various policy endorsements have been added or removed as requested by either the insurers or the insured. The named insured is UniSource Energy Corporation, although the

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was inadvertently charged to TEP. The inconsistency in the worker's compensation allocations out to capital projects in the test year is a result of migrating to the Oracle System in June 2005. During the migration to the new system, the worker's compensation allocation rates for UNS Electric were not entered and therefore, no allocation was made to capital projects from June 2005 through May 2006.

b. No.

c. In 2005 and 2006, there were a few payments inadvertently charged to TEP and UNS Gas when they should have been charged to UNS Electric; therefore, the employee deductions exceeded the amount charged to the account. In addition, there are timing differences in the payments. Premium payments to vendors are debits (expense) to the accounts, while employee deductions (withholds) are credits to the accounts.

d. The expense amounts for "Life, ST/LT Disability and ADD" are positive for the test year ending 6/30/06 because the amounts paid to the vendors for the various policies exceeded the amounts withheld from the employees' paychecks. The Company would expect to see a minimal expense in the "Life, ST/LT Disability and ADD" expense account for the following reasons:

1. Life-Union: The Company pays for the basic (1 times annual salary).
2. Life-Non Union: The Company pays for 1.5 times the annual salary.
3. LTD-Union: Employee receives enough credit to pay for 50% up to 3k per month pre and post tax. They may choose to buy up to 66 2/3% at their expense.
4. LTD-Non Union: Employee receives enough credit to pay for 50% up to 3k per month pre and post tax. They may choose to buy up to 66 2/3% at their expense.
5. ADD-Non Union only: Company pays for $20,000, no cost to employee.

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6. Business Travel Accident Insurance-Non Union: Company pays for $250,000, no cost to employee.
7. Business Travel Accident Insurance-Union: Company pays for 5 times the annual salary, no cost to employee.

RESPONDENT: Sandie Becker

WITNESS: Karen Kissinger

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coverage extends to all Directors and Officers of any owned subsidiary.

e. Yes, there were changes in allocations to UNS Electric of Officers and Directors insurance from 2004 through 2006. Please see STF11.15 (a, d & e) on the enclosed CD for the changes.

RESPONDENT: Sandie Becker

WITNESS: Karen Kissinger

UNS ELECTRIC, INC.'S RESPONSES TO
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STF 3.83 Employee Benefits.

a. List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to UNS Electric.

b. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

c. State the cost by program, of each retirement program directly charged or allocated.

d. Provide the PEP financial performance goals for 2005, 2006 and 2007.

e. For each PEP goal, for each year, show the actual results and how it compared with the target.

f. Provide the PEP in effect in each year, 2005, 2006 and 2007.

g. Show in detail how any special recognition awards recorded in the test year were determined.

h. Provide the amounts of Officer's Long-term Incentive compensation in total and charged to UNS Electric during the test year. Include supporting calculations.

SUPPLEMENTAL RESPONSE: UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Coporation and the parent Company of UNS Electric.

a. Incentives

UNS Electric non-union employees participate in UES' Performance Enhancement Program ("PEP"). The structure determines eligibility for certain bonus levels by measuring UES' performance in three areas:

- financial performance,
- operational cost containment, and
- core business and customer service goals.

Levels of achievement in each area are assigned percentage-based "scores". Those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15% to 150 % of the targeted payment level.

The financial performance and operational cost containment components each make up 30% of the bonus structure, while the

**UNS ELECTRIC, INC.'S RESPONSES TO
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core business and customer service goals account for the remaining 40 %.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages as a percent of base salary range from 3% - 14% for regular non-union employees, and 25% - 80% for Managers and Officers. Bonus percentages as a percent of base salary are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Retirement Programs
UNS Electric employees are eligible to participate in the UES Pension Plan. For a description of this plan, please see STF 3.82 (Final UES Pension SPD v1 6-28-2004), on the enclosed CD.[1] Additionally, UNS Electric employees are eligible to participate in the Tucson Electric Power Company ("TEP") 401(k) Plan as described below:

TEP 401(K) Plan
TEP's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 50% of their pay, before any deduction for state or federal income taxes. The Company matches 50 cents on the dollar, up to the first 6% of pay saved, in the 401(k) Plan for UNS Electric employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested.

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[1] This attachment is not identified by Bates numbers. UNS Electric will provide this same attachment, with Bates numbers, shortly.

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<u>TEP Salaried Employees Retirement Plan ("Salaried Plan")</u>
(This description is included because some cost is allocated back to UES for officer participation.)

The Salaried Plan provides an annual income based on the following formula:

1.6% *times* Final Average Pay
times
Years of Service (up to 25 years)

Final average pay is the average of basic monthly earnings, on the first of the month following the employee's birthday, during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement.

Years of service are based on the employee's years and months of employment with TEP or a participating affiliated corporation. The employee is vested in his or her retirement benefit after five years of service.

The maximum benefit available under the plan is an annual income of 40% of final average pay. Plan compensation for purposes of determining final average pay is limited to IRS compensation limits (Code Section) 401(a)(17). In addition, contributions to the UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred Compensation Plan") are not considered eligible compensation under the Salaried Plan.

<u>TEP Excess Benefit Plan ("Excess Plan")</u>
(This description is included because some cost is allocated back to UES for officer participation.)

The Excess Plan provides benefits to officers and other highly compensated employees in addition to the benefits payable under the Salaried Plan.

Compensation used to determine final average pay under the Salaried Plan is limited by annual IRS compensation limits (Code Section) 401(a)(17)), and is further reduced by any contributions to the Deferred Compensation Plan.

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The Excess Plan retirement benefit is calculated using the Salaried Plan formula without regard to the IRS limits on compensation, voluntary salary reductions to the Deferred Compensation Plan, and the annual incentive bonus is added to the earnings rate. The retirement benefit payable from the Excess Plan will be reduced by the benefit payable from the Salaried Plan.

UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred Compensation Plan")

The Deferred Compensation Plan allows participants (Directors, Officers and Managers) the opportunity to accumulate tax-deferred capital by allowing them to defer a portion of their pay on a pre-tax basis.

Salary and Bonus Deferral
A participant may elect to defer a percentage of their salary or bonus up to 100%. The minimum salary deferral amount is $3,500. Pay deferred under the plan is not included in W-2 earnings. Therefore, deferrals are not subject to federal or state income taxes at the time of deferral. However, deferred pay is subject to FICA and Medicare taxes in the year of deferral.

401(k) Excess Company Match
Limits on contributions to the TEP 401(k) Plan may keep highly compensated employees from receiving the full dollar-for-dollar Company match. If employees maximize their 401(k) deferral opportunity ($15,000 in 2006), the Company will contribute an amount to the Deferred Compensation Plan equal to the additional matching contribution that they would have received under the 401(k) Plan if their compensation in excess of the legal limitation ($220,000 in 2006) had been taken into account.

Receiving Account Balance
Full account balance will be distributed following retirement or termination. In the event of insolvency, plan participants will be general, unsecured creditors of the Company.

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b. SERP Expense charged to UNS Electric during the test year was $83,506.

c. Retirement Plan Expense (other than SERP) charged to UNS Electric during the test year was as follows:

UES Pension Plan	$230,361
UES 401K Plan	$ 73,112
TEP Pension/401K	$234,796
UNS Gas Pension/401K	$ 2,190
Deferred Comp Plan	$ 9,035
Total	$549,494

d. Please see STF 3.83 (d - PEP 2005) on the enclosed CD for 2005 PEP goals. The Excel file, STF 3.83 (d – PEP 2005), is not identified by Bates numbers. Please see STF 3.83 (d – PEP 2006) and STF 3.83 (d – PEP 2007), Bates Nos. UNSE(0783)08261 to UNSE(0783)08266 , on the enclosed CD, for 2006 and 2007 PEP goals for UNS Electric. STF 3.83 (d - PEP 2005), STF 3.83 (d – PEP 2006), and STF 3.83 (d – PEP 2007) contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

e. In 2005, the primary financial goal of PEP was not met; therefore, no PEP was awarded in 2005. Please see STF 3.83 (d - PEP 2005) for 2005 results. See STF 3.83 (e - PEP 2006 Final Results), Bates Nos. UNSE(0783)08267 to UNSE(0783)08268, on the enclosed CD, for the PEP 2006 program and for the 2006 results. STF 3.83 (d - PEP 2005) and STF3.83 (e - PEP 2006 Final Results) contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

f. In 2004, UES' PEP goals were separate from those of TEP. PEP had two primary goals: a financial goal specific to UES (UNS Gas and UNS Electric combined) and a set of goals measuring UNS Electric expense management, customer service, system reliability, and safety. Each of the two primary goals was weighted equally; however, PEP only paid if the primary financial goal was met. The primary UES financial goal was met in 2004.

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May 25, 2007**

In 2005, PEP had a structure similar to 2004, with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Electric financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in response STF 3.83(e) above, the 2005 primary financial goal was not met.

In 2006, the PEP structure was changed to the program that exists today. It consists of three independent primary goals, and each of the primary goals has its own trigger, meaning that if one of the primary goals is not met, there is still an opportunity to achieve the two remaining primary goals. The three primary goals are comprised of a UniSource Energy Corporation Earnings per Share goal (weighted 30%), a Cost Containment goal which manages Operations and Maintenance spending (weighted 30%), and Core Business and Customer Service goals (weighted 40%). The Core Business and Customer Service goals have many sub-goals beneath them, measuring reliability, customer service, project completion, regulatory and safety.

g. Special recognition awards were not recorded in the test year.

h. Please see STF 3.83 (h) on the enclosed CD for amounts of Officer's Long-term Incentive compensation in total and charged to UNS Electric during the test year. Supporting calculations are included in this file. STF 3.83 (h) is <u>not</u> identified by Bates numbers, contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: a. Steve Bracamonte
b. c. and h. Amy Teller
d. e. f. and g. Michael Daranyi

WITNESS: a., d., e., f., g. and h. – Dallas Dukes
b., c., and h. – Karen Kissinger

ATTACHMENTS D, E AND F TO THE COMPANY'S RESPONSE TO STAFF DATA REQUEST STF 3.83 CONTAIN INFORMATION DESIGNATED AS "CONFIDENTIAL" BY THE COMPANY AND HAS BEEN REDACTED FROM THIS DOCUMENT, ATTACHMENT RCS-5. THE CONFIDENTIAL PAGES (35-49) ARE PROVIDED UNDER SEAL IN A SEPARATE DOCUMENT.

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S ELEVENTH SET OF DATA REQUES
DOCKET NO. G-04204A-06-0463
January 18, 2007**

UNS GAS
Docket No.
G-04204A-06-0463

STF 11.5 Incentive Compensation. Refer to the response t

a. Show in detail the 2004 and 2005 PEP financ... and the actual results.

b. Show in detail how the Special Recognition Award in 2005 was determined.

c. Provide the PEP in effect during each year, 2004, 2005 and 2006.

RESPONSE:

a. Please see STF 11.5(a), Bates Nos. UNSG(0463)05831 to UNSG(0463)05832, on the enclosed CD for the 2004 and 2005 UNS Gas, Inc. ("UNS Gas") portion of PEP which includes financial performance goals and actual results. STF 11.5(a) contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

b. UNS Gas is in the process of gathering this information and will provide it shortly.

c. UNS Gas is in the process of gathering this information and will provide it shortly.

SUPPLEMENTAL RESPONSE:

a. UNS Gas' response to STF 11.5 (a) was provided to Staff on January 9, 2007.

b. As previously stated, the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Gas and Tucson Electric Power Company ("TEP"), was not met. The financial performance was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Award was paid at approximately 42% of the target for each of the three operating companies.

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463 January 18, 2007

c. In 2004, the UniSource Energy Services, Inc. ("UES") PEP goal was separate from that of TEP. It had two primary goals: a financial goal specific to UES (UNS Gas and UNS Electric combined) and a set of goals measuring UNS Gas expense management, customer service, system reliability, and safety. Each of the two primary goals was weighted equally; however, PEP only paid if the primary financial goal was met. The primary UES financial goal was met in 2004.

In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Gas financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in response to STF 11.5 b, the 2005 primary financial goal was not met.

In 2006, the PEP structure was changed to the existing program today. It consists of three independent primary goals, and each of the primary goals has its own trigger, meaning that if one of the primary goals is not met, there is opportunity to still achieve on the two remaining primary goals. The three primary goals are comprised of a UniSource Energy Corporation Earnings per Share goal (weighted 30%), a Cost Containment goal which manages Operations and Maintenance spending (weighted 30%), and Core Business and Customer Service goals (weighted 40%). The Core Business and Customer Service goals have many sub-goals beneath them, measuring reliability, customer service, project completion, regulatory and safety.

RESPONDENT: Michael Daranyi

WITNESS: Dallas Dukes

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 11, 2007**

STF 10.11 Please list by amount and account all stock based compensation expense charged to UNS Electric during the test year, including but not limited to executive stock options, the 2006 Omnibus Stock and Incentive Plan, performance share awards, accruals made pursuant to SFAS 123R and any other stock based compensation awards that resulted in costs being charged to UNS Electric during the test year.

a. Also, provide a description of each distinct stock based compensation program that resulted in charges to UNS Electric during the test year.

RESPONSE: Stock based compensation expense charged to UNS Electric during the test year is as follows:

<u>Stock Option Expense</u>

FERC 923	$ 62,904

<u>Performance Share Expense</u>

FERC 923	$ 19,969

<u>Director Stock Award Expense</u>

FERC 930	$ 45,895

<u>Dividend Equivalents on Stock Options & Stock Units</u>

FERC 920	$ 186
FERC 923	$ 33,623
FERC 930	$ (795)
Total	$ 33,014

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 11, 2007**

a. During the test year, Performance Shares and Nonqualified Stock Options were used in the compensation program. Please see STF 10.11, Bates Nos. UNSE(0783)08874 to UNSE(0783)08898, on the enclosed CD for a detailed description of each distinct stock based compensation program that resulted in charges to UNS Electric during the test year.

RESPONDENT: Amy Teller
Human Resources (a)

WITNESS: Karen Kissinger
Dallas Dukes (a)

UNS ELECTRIC, INC.'S RESPONSES TO STAFF'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 May 17, 2007

STF 3.72 Dues, Industry Associations. Are any amounts included in the test year for payments to industry associations other than those required as membership dues? If so, list the amounts and the accounts in which such contributions are recorded. For each such contribution, also state its purpose and describe how the Company perceives such expense to benefit ratepayers.

RESPONSE: Please see STF 3.72, Bates Nos. UNSE(0783)05154 to UNSE(0783)5155, on the enclosed CD for payments to industry associations other than those required as membership dues. For additional information supporting the Edison Electric Institute ("EEI") membership payment please see the response to STF 3.73.

RESPONDENT: Mina Briggs

WITNESS: Dallas Dukes

STF 3.72 = Due, Industry Associations

ENTERED INVOICES INTO ORACLE A/P
BY COST CENTER
AS OF 02-MAY-07
&FERC
&GL Month
GL Company: 033
&GL Cost Center

Co: 033

Period Name	Gl Date - Distribution	Vendor Name	Invoice Number	ET	Invoice Date	Description	Amount	FERC
DEC-05	28-DEC-2005	ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	2006-25	251	29-DEC-2005	RTN CK TO S. CROBBE (SCB09)	$250.00	0930
JUL-05	27-JUL-2005	ARIZONA UTILITY INVESTORS ASSOC	072705 500000	251	27-JUL-2005	RETURN CK TO S. FOLTZ	$2,500.00	0930
AUG-05	03-AUG-2005	ASCET	080305 4000	252	03-AUG-2005	MAIL CHECK	$40.00	0921
JAN-06	26-JAN-2006	AUSA	011706 10000	251	17-JAN-2006	ANNUAL DUES	$100.00	0930
JUL-05	28-JUL-2005	EDISON ELECTRIC INSTITUTE	1-000025467C	251	01-JUL-2005	PO 1343 MEMBERSHIP FEES	$24,071.00	0930
JAN-06	17-JAN-2006		1-000038292	251	14-DEC-2005		$10,000.00	0930
JAN-06	10-JAN-2006		1-000038367	251	14-DEC-2005	PO 1343 MEMBERSHIP FEES	$2,801.90	0930
SEP-05	30-SEP-2005	GOLDEN VALLEY CHAMBER OF COMMERCE	JULY 2005	251	14-SEP-2005	MAIL CHECK	$35.00	0930
OCT-05	21-OCT-2005		07/2005	251	13-OCT-2005	MAIL CHECK	$35.00	0930
OCT-05	14-OCT-2005	KINGMAN MOHAVE LIONS CLUB	1376	251	07-OCT-2005	MAIL CHECK	$60.00	0930
OCT-05	14-OCT-2005		1376CXL	251	07-OCT-2005	MAIL CHECK	$0.00	0930
FEB-06	27-FEB-2006		1446	252	31-JAN-2006		$60.00	0921
AUG-05	12-AUG-2005	KINGMAN ROTARY CLUB	081205 12500	252	12-AUG-2005	MAIL CHECK DUES FOR TOM FERRY	$125.00	0921
NOV-05	07-NOV-2005		102605 12500	251	26-OCT-2005	MAIL CHECK	$125.00	0930
JAN-06	26-JAN-2006		011706 13300	252	17-JAN-2006	quarterly dues/Tom Ferry	$133.00	0921
NOV-05	11-NOV-2005	KINGMAN ROUTE 66 ROTARY CLUB	100105 13250	251	01-OCT-2005	Mail ck	$132.50	0930
FEB-06	21-FEB-2006		020806 25000	252	08-FEB-2006	MAIL CHECK-DUES FOR B. ASPLIN	$250.00	0921
JUN-06	08-JUN-2006		060506 12500	251	05-JUN-2006	MAIL CHECK	$125.00	0930
AUG-05	31-AUG-2005	KINGSMEN	081505 12500	251	15-SEP-2005	MAIL CK	$125.00	0930
NOV-05	11-NOV-2005	KIWANIS CLUB OF LAKE HAVASU	110305 66600	251	03-NOV-2005	MAIL CHECK	$666.00	0930
NOV-05	29-NOV-2005	MOHAVE COMMUNITY COLLEGE	112105 7000	251	21-NOV-2005	MAIL CHECK W/ COPY OF BACKUP	$0.00	0930
AUG-05	03-AUG-2005	MOHAVE MUSEUM OF HISTORY & ARTS	080305 20000	251	03-AUG-2005	MAIL CHECK	$200.00	0930

Σ = $36,872

ENTERED INVOICES INTO ORACLE A/P
BY COST CENTER
AS OF 02-MAY-07
&FERC
&GL Month
GL Company: 033
&GL Cost Center

Co: 033

Period Name	Gl Date - Distribution	Vendor Name	Invoice Number	ET	Invoice Date	Description	Amount	FERC
JUN-06	16-JUN-2006	NOGALES-SANTA CRUZ CHAMBER OF COMMERCE	060906 6000	251	09-JUN-2006	RTN CK TO N. LUCERO (NOG-E)	$60.00	0930
AUG-05	03-AUG-2005	PETTY CASH	080305 188510	252	03-AUG-2005	RETURN CK TO A. BECKER	$35.00	0921
							Total: $41,929.40	

**UNS ELECTRIC, INC.'S RESPONSE TO
MR. MAGRUDER'S SECOND SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 19, 2007**

MM DR 2.27 USNE response to STF DR 3.55, excel spreadsheet for FERC account 930.1, on line 3, contains an invoice and payment to the Arizona Mexico Commission of $1750.00 for sponsorship. Could you please explain this expense in terms of the benefits for UNSE customers?

RESPONSE: The $1,750 for the Arizona-Mexico Commission should have been removed from expenses included in the revenue requirement. This invoice was overlooked in error and will be adjusted out of test year expense.

RESPONDENT: Edmond Beck

WITNESS: Edmond Beck

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 May 21, 2007

STF 3.55 Advertising Expense. For each of the advertising expense amounts remaining in the test year, please provide an itemization of the amount by advertising campaign/advertisement and provide a copy of the associated advertisement or ad script.

RESPONSE: UNS Electric objects to the use of the word "advertising" as it is vague and ambiguous. Examples of communications between the Company, its customers, and the public are listed below.

Please see STF 3.55 (FERC Account 930.1 Transaction Detail), provided on the enclosed CD, for an itemized list of advertising expenses incurred in the test year. The Excel file is not identified by Bates numbers.

- STF 3.55 (Bernard Hodes) – See file for the UNS Electric open position ads published in newspapers.
- STF 3.55 (Budget Billing) - See files for the art work for bill inserts and/or brochures distributed in the UNS Electric service territory, informing consumers about the Budget Billing program.
- STF 3.55 (Energy Efficiency) - See files for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing information to consumers on ways they can reduce their electric bills.
- STF 3.55 (Electrical Safety) - See for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing safety information to consumers about electricity.
- STF 3.55 (Low-Income) - See files for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing information to consumers on ways they can receive help with paying their electricity bills.
- STF 3.55 (Miscellaneous Communications) - See files for art work for ads, bill inserts and/or brochures distributed in the UNS electric service territory.
- STF 3.55 (Ad Campaigns) - See the Excel worksheet tabs for each Advertising Campaign. Each category provides the consumer

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-06-0783 May 21, 2007

communication methods used. The Excel file on the enclosed CD is not identified by Bates numbers

Due to the volume of attachments, UNS Electric is continuing to Bates Number and organize each of these documents and will provide all communications shortly.

RESPONDENT: Kimberly Mayhew

WITNESS: Dallas Dukes

SUPPLEMENTAL RESPONSE:

UNS Electric objects to the use of the word "advertising" as it is vague and ambiguous. Examples of communications between the Company, its customers, and the public are listed below.

Please see STF 3.55 (FERC Account 930.1 Transaction Detail), provided on the enclosed CD, for an itemized list of advertising expenses incurred in the test year. The Excel file is not identified by Bates numbers.

- STF 3.55 (Bernard Hodes) – See file for the UNS Electric open position ads published in newspapers. See Bates Nos. UNSE(0783)08134 to UNSE(0783)08207.

- STF 3.55 (Budget Billing) - See files for the art work for bill inserts and/or brochures distributed in the UNS Electric service territory, informing consumers about the Budget Billing program. See Bates Nos. UNSE(0783)08208 to UNSE(0783)08209.

- STF 3.55 (Electrical Safety) - See for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing safety information to consumers about electricity. See Bates Nos. UNSE(0783)08210 to UNSE(0783)08215.

- STF 3.55 (Energy Efficiency) - See files for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing information to consumers on ways they can reduce their electric bills. See Bates Nos. UNSE(0783)08216 to UNSE(0783)08236.

**UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 21, 2007**

- STF 3.55 (Low-Income) - See files for art work for ads, bill inserts and/or brochures distributed, and script for radio spots aired in the UNS Electric service territory, providing information to consumers on ways they can receive help with paying their electricity bills. See Bates Nos. UNSE(0783)08237 to UNSE(0783)08246.

- STF 3.55 (Miscellaneous Communications) - See files for art work for ads, bill inserts and/or brochures distributed in the UNS electric service territory. See Bates Nos. UNSE(0783)08247 to UNSE(0783)08256.

- STF 3.55 (Ad Campaigns) - See the Excel worksheet tabs for each Advertising Campaign. Each category provides the consumer communication methods used. The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Kimberly Mayhew

WITNESS: Dallas Dukes

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007**

STF 3.39 Refer to Attachment REW-2, Schedule E. Explain fully why, for accounts 392.xx, Transportation Equipment, Dr. White proposed a 10.0% positive net salvage for each Transportation Equipment account for the similar equipment at UNS Gas (see Attachment REW-2, Statements A and E in the UNS Gas case) versus no positive net salvage for the Transportation Equipment accounts for UNS Electric.

a. Provide all data and analysis Dr. White relied upon for his 10% positive net salvage recommendation for Transportation Equipment at UNS Gas and zero percent for Transportation Equipment at UNS Electric.
b. Please provide a complete detailed listing of the Transportation Equipment in each sub-account to Account 392 at UNS Gas and, separately at UNS Electric.
c. Please explain fully and in detail how the Transportation Equipment at UNS Gas and at UNS Electric is so different as to have a different net salvage recommendation.
d. Did Dr. White review any retirement history for Transportation Equipment at UNS Electric and/or under the previous ownership of the utility? If so, please provide the complete retirement history of Transportation Equipment at UNS Electric and under the previous ownership that Dr. White reviewed.
e. Does UNS Electric have any retirement history for Transportation Equipment at UNS Electric and/or under the previous ownership of the utility? If so, please provide the complete retirement history of Transportation Equipment at UNS Electric and under the previous ownership that UNS and its affiliates have.
f. For each sub-account of Transportation Equipment at UNS Gas and UNS Electric, please provide a detailed listing of all equipment in each such account at 12/31/06.

RESPONSE: Foster Associates inadvertently failed to include a 10 percent net salvage rate for UNS Electric transportation equipment. The impact of this oversight would be a further reduction in 2006 annualized accruals of $143,297. It is the opinion of Foster Associates that the magnitude of the additional reduction does not warrant a refiling of the depreciation study.

RESPONDENT: Dr. Ronald E. White

WITNESS: Dr. Ronald E. White

**UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007**

STF 11.8 Refer to the response to STF 3.39.

a. Please provide the detailed recalculation of the corrected depreciation rate for Transportation Equipment.

b. Please provide the detailed calculations and workpapers for the $143,297 reduction to the 2006 annualized accrual to reflect a 10 percent net salvage rate for UNS Electric transportation equipment.

RESPONSE:

a. Please see STF 11.8, Bates Nos. UNSE(0783)08910 to UNSE(0783)08919, on the enclosed CD for the detailed recalculation of the corrected depreciation rate to Transportation Equipment.

b. Please see the calculation for the $143,297 reduction below:

14,385,991 – 14,529,288 = (143,297)

RESPONDENT: Dr. Ronald White

WITNESS: Dr. Ronald White

STF 11.8

UNS ELECTRIC, INC.

Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	38.00		2.92%	30.16		5.66%	3.13%
Total Depreciable			2.92%	30.16		5.66%	3.13%
Amortizable							
302.00 Franchises and Consents	38.00			← 25 Year Amortization →			
303.00 Miscellaneous Intangible Plant	38.20			← 15 Year Amortization →			
303.WC Misc. Intangible - WAPA Fiber Optic	38.20		4.13%	← 23 Year Amortization →			
303.PC Misc.Intangible Plant - PC Software	31.00		20.00%	← 5 Year Amortization →			
Total Amortizable			4.23%	7.21		61.05%	3.06%
Total Intangible Plant			3.79%	10.88		42.49%	3.09%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	38.00		1.38%	29.50		39.14%	2.06%
342.00 Fuel Holders, Producers and Accessories	38.20		2.42%	32.63		18.12%	2.51%
343.00 Prime Movers	37.00		2.34%	26.17		34.01%	2.52%
344.00 Generators	22.60		0.67%	36.15		15.67%	2.33%
345.00 Accessory Electric Equipment	39.50		2.20%	29.39		31.13%	2.34%
346.00 Miscellaneous Power Plant Equipment	31.00		1.87%	33.34		12.06%	2.64%
Total Other Production Plant			2.00%	28.73		29.51%	2.45%
TRANSMISSION PLANT							
350.RW Rights of Way				31.35		36.69%	2.02%
352.00 Structures and Improvements	19.70		3.77%	12.75		60.36%	3.11%
353.00 Station Equipment	23.00		2.92%	21.72		31.60%	3.15%
354.00 Towers and Fixtures	12.40		4.08%	15.92		20.07%	5.02%
355.00 Poles and Fixtures	15.90	-10.0%	5.77%	12.68	-10.0%	53.37%	4.47%
356.00 Overhead Conductors and Devices	30.10		2.71%	23.85		36.63%	2.66%
359.00 Roads and Trails	44.90		2.01%	35.18		29.16%	2.01%
Total Transmission Plant			3.68%	18.90	-2.9%	39.25%	3.41%
DISTRIBUTION PLANT							
360.RW Rights of Way				27.71		43.85%	2.03%
361.00 Structures and Improvements	23.60		3.20%	25.54		24.48%	2.96%
362.00 Station Equipment	15.30		4.82%	11.54		52.96%	4.08%
364.00 Poles, Towers and Fixtures	18.90	-10.0%	4.23%	14.83	-10.0%	48.82%	4.13%
365.00 Overhead Conductors and Devices	18.40	-10.0%	4.36%	15.16	-10.0%	47.56%	4.12%
366.00 Underground Conduit	21.50		4.28%	18.66	-5.0%	34.45%	3.78%
367.00 Underground Conductors and Devices	14.30		5.36%	14.20		37.63%	4.39%
368.00 Line Transformers	14.20	-5.0%	4.93%	13.46	-5.0%	42.84%	4.62%
369.OH Services - Overhead	18.30		4.23%	14.43		45.79%	3.76%
369.UG Services - Underground	18.30		4.23%	16.26		39.13%	3.74%
370.00 Meters	26.20	-5.0%	3.25%	24.14	-5.0%	30.09%	3.10%
373.00 Street Lighting and Signal Systems	17.40		4.55%	16.64		32.89%	4.03%
Total Distribution Plant			4.50%	14.75	-6.0%	44.90%	4.15%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	27.80		2.89%	29.03		23.22%	2.64%
392.C1 Transportation Equipment - Class 1			25.00%	4.00	10.0%	44.07%	11.48%
392.C2 Transportation Equipment - Class 2			25.00%	3.02	10.0%	43.82%	15.29%
392.C3 Transportation Equipment - Class 3			25.00%	3.28	10.0%	28.71%	18.69%
392.C4 Transportation Equipment - Class 4			12.50%	1.63	10.0%	70.49%	11.97%
392.C5 Transportation Equipment - Class 5			12.50%	6.58	10.0%	15.71%	11.29%
396.00 Power Operated Equipment	8.80		3.33%	5.16		64.53%	6.87%
Total Depreciable			12.12%	4.13	6.9%	49.82%	10.29%

8/5/2007

Statement A

UNS ELECTRIC, INC.
Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
Amortizable							
391.10 Office Furniture and Equipment	17.60		3.72%	← 21 Year Amortization →			
391.20 Computer Equipment - PCs			20.00%	← 5 Year Amortization →			
393.00 Stores Equipment	28.10		2.62%	← 33 Year Amortization →			
394.00 Tools, Shop and Garage Equipment	23.80		3.02%	← 29 Year Amortization →			
395.00 Laboratory Equipment	33.30		2.41%	← 40 Year Amortization →			
397.CE Communication Equipment	17.60		4.13%	← 23 Year Amortization →			
398.00 Miscellaneous Equipment	11.60		5.45%	← 18 Year Amortization →			
Total Amortizable			5.10%	11.20		41.95%	3.65%
Total General Plant			8.97%	6.21	-4.7%	46.29%	7.31%
TOTAL UTILITY			4.53%	14.29	-4.7%	43.58%	4.14%

Statement B

UNS ELECTRIC, INC.

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
Depreciable				
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415	$103,906	$111,378	$7,472
Total Depreciable	$3,558,415	$103,906	$111,378	$7,472
Amortizable				
302.00 Franchises and Consents	$11,908		$54	$54
303.00 Miscellaneous Intangible Plant	4,219,098		141,762	141,762
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	69,591	73,298	3,707
303.PC Misc.Intangible Plant - PC Software	1,145,223	229,045	1,145	(227,900)
Total Amortizable	$7,061,229	$298,636	$216,259	($82,377)
Total Intangible Plant	$10,619,644	$402,542	$327,637	($74,905)
OTHER PRODUCTION PLANT				
341.00 Structures and Improvements	$619,244	$8,546	$12,756	$4,210
342.00 Fuel Holders, Producers and Accessories	631,364	15,279	15,847	568
343.00 Prime Movers	8,684,079	203,207	218,839	15,632
344.00 Generators	2,309,132	15,471	53,803	38,332
345.00 Accessory Electric Equipment	1,685,197	37,074	39,434	2,360
346.00 Miscellaneous Power Plant Equipment	493,979	9,237	13,041	3,804
Total Other Production Plant	$14,422,995	$288,814	$353,720	$64,906
TRANSMISSION PLANT				
350.RW Rights of Way	$346,016		$6,990	$6,990
352.00 Structures and Improvements	191,668	7,226	5,961	(1,265)
353.00 Station Equipment	17,657,646	515,603	556,216	40,613
354.00 Towers and Fixtures	521,825	21,290	26,196	4,906
355.00 Poles and Fixtures	12,285,169	708,854	549,147	(159,707)
356.00 Overhead Conductors and Devices	11,245,657	304,757	299,134	(5,623)
359.00 Roads and Trails	183,860	3,696	3,696	
Total Transmission Plant	$42,431,841	$1,561,426	$1,447,340	($114,086)
DISTRIBUTION PLANT				
360.RW Rights of Way	$86,619		$1,758	$1,758
361.00 Structures and Improvements	3,398,247	108,744	100,588	(8,156)
362.00 Station Equipment	28,402,465	1,368,999	1,158,821	(210,178)
364.00 Poles, Towers and Fixtures	75,596,882	3,197,748	3,122,151	(75,597)
365.00 Overhead Conductors and Devices	48,310,770	2,106,350	1,990,404	(115,946)
366.00 Underground Conduit	12,126,868	519,030	458,396	(60,634)
367.00 Underground Conductors and Devices	22,976,392	1,231,535	1,008,664	(222,871)
368.00 Line Transformers	45,658,424	2,250,960	2,109,419	(141,541)
369.OH Services - Overhead	7,297,945	308,703	274,403	(34,300)
369.UG Services - Underground	3,315,090	140,228	123,984	(16,244)
370.00 Meters	9,368,222	304,467	290,415	(14,052)
373.00 Street Lighting and Signal Systems	3,769,729	171,523	151,920	(19,603)
Total Distribution Plant	$260,307,653	$11,708,287	$10,790,923	($917,364)

6/5/2007

UNS ELECTRIC, INC.

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
GENERAL PLANT				
Depreciable				
390.00 Structures and Improvements	$2,445,738	$70,682	$64,567	($6,115)
392.C1 Transportation Equipment - Class 1	366,331	91,583	42,055	(49,528)
392.C2 Transportation Equipment - Class 2	882,290	220,573	134,902	(85,671)
392.C3 Transportation Equipment - Class 3	1,007,316	251,829	188,267	(63,562)
392.C4 Transportation Equipment - Class 4	4,808,218	601,027	575,544	(25,483)
392.C5 Transportation Equipment - Class 5	584,467	73,058	65,986	(7,072)
396.00 Power Operated Equipment	968,258	32,243	66,519	34,276
Total Depreciable	$11,062,618	$1,340,995	$1,137,840	($203,155)
Amortizable				
391.10 Office Furniture and Equipment	$2,297,349	$85,461	$103,610	$18,149
391.20 Computer Equipment - PCs	868,777	173,755	15,030	(158,725)
393.00 Stores Equipment	122,871	3,219	3,698	479
394.00 Tools, Shop and Garage Equipment	2,391,755	72,231	79,406	7,175
395.00 Laboratory Equipment	808,108	19,475	20,203	728
397.CE Communication Equipment	2,391,716	98,778	100,691	1,913
398.00 Miscellaneous Equipment	114,643	6,248	5,893	(355)
Total Amortizable	$8,995,219	$459,167	$328,531	($130,636)
Total General Plant	$20,057,837	$1,800,162	$1,466,371	($333,791)
TOTAL UTILITY	$347,839,970	$15,761,231	$14,385,991	($1,375,240)

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415	$238,117	6.69%	$204,609	5.75%	$201,261	5.66%
Total Depreciable	$3,558,415	$238,117	6.69%	$204,609	5.75%	$201,261	5.66%
Amortizable							
302.00 Franchises and Consents	$11,908	$0		$11,775	98.88%	$11,775	98.88%
303.00 Miscellaneous Intangible Plant	4,219,098	267,350	6.34%	2,971,824	70.44%	2,971,824	70.44%
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	159,478	9.46%	183,152	10.87%	183,152	10.87%
303.PC Misc.Intangible Plant - PC Software	1,145,223	1,178,678	102.92%	1,144,041	99.90%	1,144,041	99.90%
Total Amortizable	$7,061,229	$1,605,507	22.74%	$4,310,792	61.05%	$4,310,792	61.05%
Total Intangible Plant	$10,619,644	$1,843,624	17.36%	$4,515,401	42.52%	$4,512,053	42.49%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	$619,244	$367,625	59.37%	$246,434	39.80%	$242,402	39.14%
342.00 Fuel Holders, Producers and Accessories	631,364	121,053	19.17%	116,329	18.43%	114,426	18.12%
343.00 Prime Movers	8,684,079	2,637,958	30.38%	3,002,520	34.58%	2,953,395	34.01%
344.00 Generators	2,309,132	254,855	11.04%	367,850	15.93%	361,832	15.67%
345.00 Accessory Electric Equipment	1,685,197	450,671	26.74%	533,384	31.65%	524,658	31.13%
346.00 Miscellaneous Power Plant Equipment	493,979	71,873	14.55%	60,577	12.26%	59,586	12.06%
Total Other Production Plant	$14,422,995	$3,904,034	27.07%	$4,327,095	30.00%	$4,256,297	29.51%
TRANSMISSION PLANT							
350.RW Rights of Way	$346,016	$1		$129,064	37.30%	$126,952	36.69%
352.00 Structures and Improvements	191,668	147,919	77.17%	117,614	61.36%	115,690	60.36%
353.00 Station Equipment	17,657,646	6,525,850	36.96%	5,672,519	32.13%	5,579,708	31.60%
354.00 Towers and Fixtures	521,825	144,146	27.62%	106,452	20.40%	104,711	20.07%
355.00 Poles and Fixtures	12,285,169	6,414,872	52.22%	6,665,775	54.26%	6,556,714	53.37%
356.00 Overhead Conductors and Devices	11,245,657	4,276,151	38.02%	4,187,528	37.24%	4,119,014	36.63%
359.00 Roads and Trails	183,860	73,249	39.84%	54,496	29.64%	53,604	29.16%
Total Transmission Plant	$42,431,841	$17,582,187	41.44%	$16,933,449	39.91%	$16,656,393	39.25%
DISTRIBUTION PLANT							
360.RW Rights of Way	$86,619	$0		$38,615	44.58%	$37,983	43.85%
361.00 Structures and Improvements	3,398,247	824,191	24.25%	845,564	24.88%	831,729	24.48%
362.00 Station Equipment	28,402,465	14,346,966	50.51%	15,291,887	53.84%	15,041,690	52.96%

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
364.00 Poles, Towers and Fixtures	75,596,882	35,977,383	47.59%	37,523,576	49.64%	36,909,637	48.82%
365.00 Overhead Conductors and Devices	48,310,770	22,914,406	47.43%	23,357,935	48.35%	22,975,766	47.56%
366.00 Underground Conduit	12,126,868	4,060,572	33.48%	4,247,436	35.03%	4,177,941	34.45%
367.00 Underground Conductors and Devices	22,976,392	9,724,089	42.32%	8,790,967	38.26%	8,647,135	37.63%
368.00 Line Transformers	45,658,424	21,572,430	47.25%	19,885,236	43.55%	19,559,885	42.84%
369.OH Services - Overhead	7,297,945	3,359,775	46.04%	3,397,599	46.56%	3,342,009	45.79%
369.UG Services - Underground	3,315,090	1,044,451	31.51%	1,318,669	39.78%	1,297,094	39.13%
370.00 Meters	9,368,222	2,871,949	30.66%	2,865,926	30.59%	2,819,036	30.09%
373.00 Street Lighting and Signal Systems	3,769,729	1,250,480	33.17%	1,260,597	33.44%	1,239,972	32.89%
Total Distribution Plant	$260,307,653	$117,946,692	45.31%	$118,824,008	45.65%	$116,879,878	44.90%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$2,445,738	$800,583	32.73%	$577,323	23.61%	$567,877	23.22%
392.C1 Transportation Equipment - Class 1	366,331	274,470	74.92%	164,116	44.80%	161,431	44.07%
392.C2 Transportation Equipment - Class 2	882,290	615,312	69.74%	393,051	44.55%	386,620	43.82%
392.C3 Transportation Equipment - Class 3	1,007,316	706,361	70.12%	294,023	29.19%	289,213	28.71%
392.C4 Transportation Equipment - Class 4	4,808,218	4,578,490	95.22%	3,445,689	71.66%	3,389,313	70.49%
392.C5 Transportation Equipment - Class 5	584,467	95,384	16.32%	93,369	15.98%	91,841	15.71%
396.00 Power Operated Equipment	968,258	732,737	75.68%	635,177	65.60%	624,785	64.53%
Total Depreciable	$11,062,618	$7,803,339	70.54%	$5,602,749	50.65%	$5,511,080	49.82%
Amortizable							
391.10 Office Furniture and Equipment	$2,297,349	$764,125	33.26%	$912,876	39.74%	$912,876	39.74%
391.20 Computer Equipment - PCs	868,777	62,880	7.24%	851,825	98.05%	851,825	98.05%
393.00 Stores Equipment	122,871	57,010	46.40%	68,689	55.90%	68,689	55.90%
394.00 Tools, Shop and Garage Equipment	2,391,755	950,482	39.74%	1,096,139	45.83%	1,096,139	45.83%
395.00 Laboratory Equipment	808,108	198,068	24.51%	286,621	35.47%	286,621	35.47%
397.CE Communication Equipment	2,391,716	387,217	16.19%	473,306	19.79%	473,306	19.79%
398.00 Miscellaneous Equipment	114,643	89,560	78.12%	84,062	73.33%	84,062	73.33%
Total Amortizable	$8,995,219	$2,509,343	27.90%	$3,773,518	41.95%	$3,773,518	41.95%
Total General Plant	$20,057,837	$10,312,681	51.41%	$9,376,267	46.75%	$9,284,598	46.29%
TOTAL UTILITY	$347,839,970	$151,589,220	43.58%	$153,976,220	44.27%	$151,589,220	43.58%

UNS ELECTRIC, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT									
Depreciable									
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415		$3,558,415						
Total Depreciable	$3,558,415		$3,558,415						
Amortizable									
302.00 Franchises and Consents	$11,908		$11,908						
303.00 Miscellaneous Intangible Plant	4,219,099	1	4,219,098						
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000		1,685,000						
303.PC Misc.Intangible Plant - PC Software	1,145,223		1,145,223						
Total Amortizable	$7,061,230	$1	$7,061,229						
Total Intangible Plant	$10,619,645	$1	$10,619,644						
OTHER PRODUCTION PLANT									
341.00 Structures and Improvements	$619,244		$619,244						
342.00 Fuel Holders, Producers and Accessories	631,364		631,364						
343.00 Prime Movers	10,707,541	2,023,462	8,684,079						
344.00 Generators	2,356,732	47,600	2,309,132						
345.00 Accessory Electric Equipment	1,904,534	219,337	1,685,197						
346.00 Miscellaneous Power Plant Equipment	503,598	9,619	493,979						
Total Other Production Plant	$16,723,013	$2,300,018	$14,422,995						
TRANSMISSION PLANT									
350.RW Rights of Way	$346,016		$346,016						
352.00 Structures and Improvements	191,668		191,668						
353.00 Station Equipment	17,697,125	39,479	17,657,646						
354.00 Towers and Fixtures	521,825		521,825						
355.00 Poles and Fixtures	12,393,414	108,245	12,285,169		-10.0%		(1,228,517)	(1,228,517)	-9.9%
356.00 Overhead Conductors and Devices	11,267,316	21,659	11,245,657						
359.00 Roads and Trails	183,860		183,860						
Total Transmission Plant	$42,601,224	$169,383	$42,431,841		-2.9%		($1,228,517)	($1,228,517)	-2.9%
DISTRIBUTION PLANT									
360.RW Rights of Way	$86,619		$86,619						
361.00 Structures and Improvements	3,409,388	11,141	3,398,247						
362.00 Station Equipment	28,425,896	23,431	28,402,465						
364.00 Poles, Towers and Fixtures	76,698,662	1,101,780	75,596,882	-0.8%	-10.0%	(8,814)	(7,559,688)	(7,568,502)	-9.9%
365.00 Overhead Conductors and Devices	49,287,987	977,217	48,310,770	-1.8%	-10.0%	(17,590)	(4,831,077)	(4,848,667)	-9.8%
366.00 Underground Conduit	12,235,191	108,323	12,126,868	0.1%	-5.0%	108	(606,343)	(606,235)	-5.0%
367.00 Underground Conductors and Devices	23,284,235	307,843	22,976,392	-0.8%		(2,463)		(2,463)	
368.00 Line Transformers	47,077,581	1,419,157	45,658,424	-5.9%	-5.0%	(83,730)	(2,282,921)	(2,366,651)	-5.0%
369.OH Services - Overhead	7,297,945		7,297,945						
369.UG Services - Underground	3,315,090		3,315,090						
370.00 Meters	9,760,332	392,110	9,368,222		-5.0%		(468,411)	(468,411)	-4.8%
373.00 Street Lighting and Signal Systems	3,840,377	70,648	3,769,729						
Total Distribution Plant	$264,719,303	$4,411,650	$260,307,653	-2.5%	-6.0%	($112,489)	($15,748,441)	($15,860,930)	-6.0%

UNS ELECTRIC, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$2,445,743	$5	$2,445,738						
392.C1 Transportation Equipment - Class 1	456,297	89,966	366,331	8.0%	10.0%	7,197	36,633	43,830	9.6%
392.C2 Transportation Equipment - Class 2	1,163,990	301,700	882,290	9.0%	10.0%	27,153	88,229	115,362	9.7%
392.C3 Transportation Equipment - Class 3	1,802,214	794,898	1,007,316	3.9%	10.0%	31,001	100,732	131,733	7.3%
392.C4 Transportation Equipment - Class 4	4,853,150	44,932	4,808,218	12.9%	10.0%	5,796	480,822	486,618	10.0%
392.C5 Transportation Equipment - Class 5	584,467		584,467		10.0%		58,447	58,447	10.0%
396.00 Power Operated Equipment	968,258		968,258						
Total Depreciable	$12,294,119	$1,231,501	$11,062,618	5.8%	6.9%	$71,148	$764,862	$836,010	6.8%
Amortizable									
391.10 Office Furniture and Equipment	$5,955,915	$3,658,566	$2,297,349						
391.20 Computer Equipment - PCs	868,777		868,777						
393.00 Stores Equipment	122,871		122,871						
394.00 Tools, Shop and Garage Equipment	2,455,025	63,270	2,391,755						
395.00 Laboratory Equipment	864,222	56,114	808,108						
397.CE Communication Equipment	2,432,124	40,408	2,391,716						
398.00 Miscellaneous Equipment	114,643		114,643						
Total Amortizable	$12,813,577	$3,818,358	$8,995,219						
Total General Plant	$25,107,696	$5,049,859	$20,057,837	1.4%	3.8%	$71,148	$764,862	$836,010	3.3%
TOTAL UTILITY	$359,770,881	$11,930,911	$347,839,970	-0.3%	-4.7%	($41,341)	($16,212,096)	($16,253,437)	-4.5%

UNS ELECTRIC, INC.
Present and Proposed Parameters
Broad Group Procedure

Statement E

Account Description	Present P-Life/ AYFR	Present Curve Shape	Present BG ASL	Present Rem. Life	Present Avg. Sal.	Present Fut. Sal.	Proposed P-Life/ AYFR	Proposed Curve Shape	Proposed BG ASL	Proposed Rem. Life	Proposed Avg. Sal.	Proposed Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
Depreciable												
303.WP Misc. Intangible - WAPA Switchboard	49.00	S6	49.00	38.00			32.00	R1	32.00	30.16		
Total Depreciable									32.00	30.16		
Amortizable												
302.00 Franchises and Consents	49.00	S6	49.00	38.00			25.00	SQ	25.00	2.50		
303.00 Miscellaneous Intangible Plant	40.00	S4	40.00	38.20			15.00	SQ	15.00	8.81		
303.WO Misc. Intangible - WAPA Fiber Optic	40.00	S4	40.00	38.20			23.00	SQ	23.00	20.50		
303.PC Misc.Intangible Plant - PC Software	36.00	R1	36.00	31.00			5.00	SQ	5.00	1.00		
Total Amortizable									12.09	7.21		
Total Intangible Plant									15.27	10.88		
OTHER PRODUCTION PLANT												
341.00 Structures and Improvements	49.00	S6	49.00	38.00			49.00	S6	49.00	29.50		
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	38.20			40.00	S4	40.00	32.63		
343.00 Prime Movers	40.00	R3	40.00	37.00			40.00	R3	40.00	26.17		
344.00 Generators	43.00	S0	43.00	22.60			43.00	S0	43.00	36.15		
345.00 Accessory Electric Equipment	43.00	S6	43.00	39.50			43.00	S6	43.00	29.39		
346.00 Miscellaneous Power Plant Equipment	38.00	R1	36.00	31.00			38.00	R1	38.00	33.34		
Total Other Production Plant									41.04	28.73		
TRANSMISSION PLANT												
350.RW Rights of Way							50.00	SQ	50.00	31.35		
352.00 Structures and Improvements	33.00	R3	33.00	19.70			33.00	R3	33.00	12.75		
353.00 Station Equipment	32.00	R1	32.00	23.00			32.00	R1	32.00	21.72		
354.00 Towers and Fixtures	20.00	L0	20.00	12.40			20.00	L0	20.00	15.92		
355.00 Poles and Fixtures	25.00	S5	25.00	15.90	-10.0	-10.0	25.00	S5	25.00	12.68	-9.9	-10.0
356.00 Overhead Conductors and Devices	38.00	L3	38.00	30.10			38.00	L3	38.00	23.85		
359.00 Roads and Trails	50.00	SQ	50.00	44.90			50.00	SQ	50.00	35.18		
Total Transmission Plant									30.71	18.90	-2.9	-2.9
DISTRIBUTION PLANT												
360.RW Rights of Way							50.00	SQ	50.00	27.71		
361.00 Structures and Improvements	34.00	R4	34.00	23.60			34.00	R4	34.00	25.54		
362.00 Station Equipment	25.00	S4	25.00	15.30			25.00	S4	25.00	11.54		
364.00 Poles, Towers and Fixtures	27.00	S4	27.00	18.90	-10.0	-10.0	27.00	S4	27.00	14.83	-9.9	-10.0
365.00 Overhead Conductors and Devices	27.00	S3	27.00	18.40	-10.0	-10.0	27.00	S3	27.00	15.16	-9.8	-10.0

UNS ELECTRIC, INC.
Present and Proposed Parameters
Broad Group Procedure

Statement E

Account Description	Present Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
366.00 Underground Conduit	28.00	S2	26.00	21.50			28.00	S2	28.00	18.66	-5.0	-5.0
367.00 Underground Conductors and Devices	23.00	S3	23.00	14.30			23.00	S3	23.00	14.20		
368.00 Line Transformers	23.00	S4	23.00	14.20	-5.0	-5.0	23.00	S4	23.00	13.46	-5.0	-5.0
369.OH Services - Overhead	27.00	R5	27.00	18.30			27.00	R5	27.00	14.43		
369.UG Services - Underground	27.00	R5	27.00	18.30			27.00	R5	27.00	16.26		
370.00 Meters	34.00	R3	34.00	26.20	-5.0	-5.0	34.00	R3	34.00	24.14	-4.8	-5.0
373.00 Street Lighting and Signal Systems	25.00	S4	25.00	17.40			25.00	S4	25.00	16.64		
Total Distribution Plant									25.87	14.75	-6.0	-6.0
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	36.00	27.80			38.00	R2	38.00	29.03		
392.C1 Transportation Equipment - Class 1							8.00	L1.5	8.00	4.00	9.6	10.0
392.C2 Transportation Equipment - Class 2							6.00	L2	6.00	3.02	9.7	10.0
392.C3 Transportation Equipment - Class 3							5.00	S5	5.00	3.28	7.3	10.0
392.C4 Transportation Equipment - Class 4							8.00	S4	8.00	1.63	10.0	10.0
392.C5 Transportation Equipment - Class 5							8.00	S4	8.00	6.58	10.0	10.0
396.00 Power Operated Equipment	15.00	S5	15.00	6.80			15.00	S5	15.00	5.16		
Total Depreciable									9.24	4.13	6.8	6.9
Amortizable												
391.10 Office Furniture and Equipment	21.00	R2	21.00	17.60			21.00	SQ	21.00	13.37		
391.20 Computer Equipment - PCs	5.00		5.00				5.00	SQ	5.00	1.13		
393.00 Stores Equipment	33.00	S6	33.00	28.10			33.00	SQ	33.00	14.67		
394.00 Tools, Shop and Garage Equipment	29.00	S-.5	29.00	23.80			29.00	SQ	29.00	16.32		
395.00 Laboratory Equipment	40.00	R4	40.00	33.30			40.00	SQ	40.00	25.85		
397.CE Communication Equipment	23.00	R1.5	23.00	17.60			23.00	SQ	23.00	19.07		
398.00 Miscellaneous Equipment	18.00	R4	18.00	11.60			18.00	SQ	18.00	5.19		
Total Amortizable									17.99	11.20		
Total General Plant									11.82	6.21	-4.5	-4.7
TOTAL UTILITY									24.51	14.29	-4.5	-4.7

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007**

STF 3.70 Cost-saving Programs. Please list and describe in detail any cost-saving programs implemented during the period 2005 through the present. For each program listed in response to this request, show the anticipated and achieved savings. Include calculations of savings amounts and explain any assumptions used in such calculations. For each cost-saving program listed, provide the cost-benefit analyses for each program. Show the impact of each such cost-saving program on the test year.

RESPONSE: Meter Reading Services:
UNS Electric entered into a meter reading services agreement with SES in February 2005. The term of the agreement is three (3) years. The contractor reads electric meters in Kingman and Lake Havasu City service territories.

The average monthly invoice for meter reading services has been reduced by approximately $10,000 from UNS Electric's prior meter reading services provider (GuardForce).

RESPONDENT: Paula Baxter

WITNESS: Thomas Ferry

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 11, 2007**

STF 10.4 Were there any charges from Southwest Energy Services directly to UNS Electric during the test year? If so, please provide the amounts by account for all such charges, and provide comparable information for calendar 2005 and 2006.

RESPONSE: Southwest Energy Services ("SES") submitted invoices to UNS Electric totaling $637,813 for services provided in 2005, and $772,853 for services provided in 2006. Some of these invoices included services for UNS Gas, Inc. ("UNS Gas") and UNS Electric charged these amounts to UNS Gas accordingly. The following is a summary of how these invoices were charged during the test-year. Also included is comparable data for 2005 and 2006.

Test-Year Ended June 30, 2006	
UNE FERC 107	$ 208
UNE FERC 163	$ 34,539
UNE FERC 902	$ 547,400
UNE FERC 903	$ 6,746
Charged to UNS Gas	$ 101,065
Total	$ 689,958
2005 Invoices	
UNE FERC 163	$ 56,780
UNE FERC 902	$ 515,562
Charged to UNS Gas	$ 65,471
Total	$ 637,813
2006 Invoices	
UNE FERC 107	$ 3,282
UNE FERC 163	$ 32,095
UNE FERC 596	$ 15,701
UNE FERC 902	$ 591,550
UNE FERC 903	$ 8,411
Charged to TEP in error ***	$ 27,169
Charged to UNS Gas	$ 94,645
Total	$ 772,853

*** This invoice was charged to and paid by Tucson Electric Power Company ("TEP") in error. It should have been charged to UNE FERC 902

RESPONDENT: Amy Teller

WITNESS: Karen Kissinger

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 11, 2007**

STF 10.5 Were there any charges from Southwest Energy Services indirectly from TEP or another affiliate to UNS Electric during the test year? If so, please provide the amounts by account for all such charges, and provide comparable information for calendar 2005 and 2006.

RESPONSE: SES provides services to TEP on a regular basis. Some of these invoices include services for UNS Electric which are charged to UNS Electric accordingly. The following is a summary of TEP's SES invoices charged to UNS Electric during the test-year. Also included is comparable data for 2005 and 2006.

Test-Year Ended June 30, 2006	
UNE FERC 107	$ 27,981
UNE FERC 163	$ 3,155
UNE FERC 184	$ 8,009
UNE FERC 583	$ 11
UNE FERC 588	$ 4,178
UNE FERC 595	$ 1,203
UNE FERC 596	$ 806
Total	$ 45,343
2005	
UNE FERC 107	$ 9,110
UNE FERC 163	$ 56
UNE FERC 184	$ 910
UNE FERC 583	$ 11
UNE FERC 588	$ 2,093
UNE FERC 595	$ 217
Total	$ 12,397
2006	
UNE FERC 107	$ 29,501
UNE FERC 108	$ 718
UNE FERC 163	$ 3,473
UNE FERC 184	$ 27,243
UNE FERC 588	$ 43,825
UNE FERC 595	$ 1,531
UNE FERC 903	$ 333
Total	$ 106,624

RESPONDENT: Amy Teller

WITNESS: Karen Kissinger

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S TENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 11, 2007**

STF 10.6 When Southwest Energy Services provides supplemental work force services for UNS Electric, TEP or other affiliates, is there any markup above payroll cost included in such charges? If so, please describe how the billing rates for SES supplemental work force are determined and identify all components of such rates above the base payroll cost paid by SES.

RESPONSE: When SES provides supplemental work force services to UNS Electric, TEP or other affiliates, SES charges a 10% mark-up on the base wages of the supplemental worker.

In addition, SES charges the cost of employer's taxes, workers' compensation and benefits. For example, for a supplemental administrative assistant that is paid $12.00 per hour, SES would charge ($12.00 + $1.20 markup) per hour; plus employer's taxes, workers' compensation, and benefits (cost).

RESPONDENT: Bob Dame

WITNESS: Karen Kissinger

**UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007**

STF 11.10 Refer to the response to STF 3.70.

a. Please provide the contract with SES.

b. What is the total expense to UNS Electric for the test year, by account, for the meter reading services provided by SES?

c. Is SES an affiliated company? If so, please answer parts d through i.

d. Please show in detail how the pricing for SES services to be provided to UNS Electric was developed.

e. What is the profit margin to SES for the meter reading services it provides to UNS Electric?

f. Does SES have audited or unaudited financial statements? Please provide such statements for 2005 and 2006.

g. Does SES have earnings statements or balance sheets? Please provide such documents for 2005 and 2006.

h. What is the markup over cost for the meter reading services that SES provides to UNS Electric? Provide for 2005 and 2006.

i. How is the markup over cost for the meter reading services that SES provides to UNS Electric determined? Show calculations for 2005 and 2006.

RESPONSE:

a. Please see the response to STF 3.58, Bates Nos. UNSE(0783)05042 through UNSE(0783)05046 for a copy of the meter reading services contract with SES.

b. Please see STF 11.10 (b) on the enclosed CD for the meter reading expense in FERC 902 provided by SES. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

c. Yes, SES is an affiliated company.

d. Please see STF 11.10(d), Bates No. UNSE(0783)08920, on the enclosed CD for the original estimate on how much it would cost to operate the business unit and how much SES would have to charge per read. SES was competing against the former vendor who was doing the reads at $.65 the previous year. SES ended up going with the $.65 knowing it was a little under what was needed, but had to remain competitive with the market. SES began reading

**UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
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UniSource Energy Service, Inc.'s electric meter reads in February 2005.

e. There is no profit margin directly included in the "per read" charges assessed to UNS Electric by SES. Using the competitive "per read" rate, SES After-Tax profit was projected at 5.5%. In 2005, the actual After-Tax profit was $13,000 or 1.9% and in 2006 the After-Tax profit was $42,000 or 4.6% (2006 includes income and operating expenses for the City of Kingman Water Meter Reading that began in August of 2006).

f., g. SES does not have audited financial statements. Please see STF 11.10 (f-g) on the enclosed CD for the SES balance sheets as of December 31, 2005 and 2006 and the SES income statements for the years ended December 31, 2005 and 2006. STF 11.10 (f & g) contains confidential information and is being provided pursuant to the terms of the Protective Agreement. The Excel file on the enclosed CD is not identified by Bates numbers.

h. As demonstrated in the above statements, the markup over cost for 2005 was $13,000 and for 2006 was $42,000. The City of Kingman Water Meter Reads are included in 2006.

i. Per the three year contract, SES increases the billing rate $.02 per read, per year. In 2005 the rate was $.65 per read, in 2006 it was increased to $.67 per read and in 2007 it is currently $.69 per read. The $.02 increase represents a budgeted increase of 3% each year to off-set the cost of wage increases.

RESPONDENT: Mina Briggs, Janet Zaidenberg-Schrum, Bob Dame and Tom Ferry

WITNESS: Tom Ferry

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S FIFTEENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 26, 2007**

STF 15.1 Southwest Energy Services (SES) charges. Refer to the responses to STF 10.4, STF 10.5, and STF 10.6.

a. The response to STF 10.6 indicates that "SES charges a 10% mark-up on the base wages of the supplemental worker." For each of the amounts of SES charges listed on the responses to STF 10.4 and STF 10.5, please identify the amount of the SES 10% mark-up over base wages. If exact amounts are not available, please provide the Company's best estimates of the SES 10% mark-up charges and show how such estimates were derived.

b. Do the SES charges to UNS Electric listed in the responses to STF 10.4 and STF 10.5 include any incentive compensation in the benefits cost? If so, please identify the amount of incentive compensation included in the SES charges to UNS Electric listed in the responses to STF 10.4 and STF 10.5.

c. Please list the benefits cost, by type of benefit, that is included in the SES charges to UNS Electric.

d. Is the 10% SES mark-up over base wages specified in a written contract? If so, please provide the contract, and indicate specifically where in the contract the 10% markup is specified.

RESPONSE: UNS Electric is in the process of gathering information and will provide the response to this data request as soon as the compilation is complete.

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007**

STF 3.19 Please provide all of the Company's actuarial service life data, which was sorted by age, in Excel if available or in Excel-readable format if not already in Excel.

RESPONSE: Please see STF 3.19 (Database) on the enclosed CD. The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Dr. Ronald E. White

WITNESS: Dr. Ronald E. White

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 17, 2007**

STF 3.30 For each plant account, please provide the actual cost of removal and net salvage information for each year, 2000 through 2005.

RESPONSE: Please see the response to STF 3.19. Neither Foster Associates nor UNS Electric has actual cost of removal and net salvage information for calendar years other than 2005.

RESPONDENT: Dr. Ronald E. White

WITNESS: Dr. Ronald E. White

UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007

STF 11.2 CWIP and Black Mountain Generating Station

a. Does any portion of the Company's request for $10,761,154 of CWIP in rate base (Adjustment UNSE-3) relate to the Black Mountain Generating Station?

b. If so, please identify all amounts included in the Company's request for $10,761,154 of CWIP in rate base that relate to the Black Mountain Generating Station.

c. Does any portion of the Company's proposed pro forma adjustments (shown on Schedule C-2, page 4, lines 7 and 8) for depreciation and property taxes, respectively, relate to the Black Mountain Generating Station?

d. If so, please identify all amounts included in the Company's proposed pro forma adjustments for depreciation and property taxes, respectively, that relate to the Black Mountain Generating Station.

RESPONSE:

a. No.

b. Not applicable.

c. No.

d. Not applicable.

RESPONDENT: Carl Dabelstein

WITNESS: Karen Kissinger

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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SCHEDULES

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I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Please summarize your education background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in about 400 utility proceedings before some 40 regulatory agencies in the United States and Canada. Schedule 1 provides a more complete description of my education and relevant work experience.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") proceedings, including the recent electric rate case involving Arizona Public Service Company (Docket No. E-01345A-05-0816) and the recent gas rate case involving UNS Gas, Inc. (Docket No. G-01345A-05-0463). Those testimonies were provided on behalf of the Commission Staff.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by the Commission Staff to evaluate the cost of capital aspects of the current filing of UNS Electric, Inc. ("UNS Electric"). I have performed independent studies and am making recommendations of the current cost of capital for UNS Electric. In addition, because UNS Electric is a subsidiary of UniSource Energy Corporation ("UniSource Energy"), I also have evaluated this entity in my analyses.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 14. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for UNS Electric are:

	Percent	Cost	Return
Short-Term Debt	3.96%	6.36%	0.25%
Long-Term Debt	47.21%	8.16%	3.85%
Common Equity	48.83%	9.5-10.5%	4.64-5.13%
Total	100.00%		8.74-9.23%
			8.99% mid-point

UNS Electric's application requests a return on common equity of 11.8 percent and overall rate of return of 9.89 percent.

Q. Please summarize your cost of capital analyses and related conclusions for UNS Electric.

A. This proceeding is concerned with UNS Electric's regulated electric distribution utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. UNS Electric's proposed capital structure is its capital structure as of June 30, 2007. I use the actual test period capital structure of UNS Electric as of June 30, 2006 in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rates of long-term debt and short-term debt. I have used the test period 8.16 percent cost rate for long-term debt and 6.36 percent cost of short-term debt contained in UNS Electric's application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for UNS Electric. Each of these methodologies is applied to two groups: one of proxy combination electric and gas utilities, and the proxy group used by UNS Electric Witness Grant. These three methodologies and my findings are:

Methodology	Range	
Discounted Cash Flow	9.5-10.5%	(10.0% mid-point)
Capital Asset Pricing Model	10.0-10.5%	(10.25% mid-point)
Comparable Earnings	10.0%	

Based upon these findings, I conclude that the cost of common equity for UNS Electric is within a range of 9.5 percent to 10.5 percent (10.0 percent mid-point), which reflects each of the model results.

Using the results from these three steps, I have calculated a weighted cost of capital (overall rate of return) range of 8.74 percent to 9.23 percent (8.99 percent mid-point, which incorporates a cost of common equity of 10.0 percent). My specific cost of capital recommendation for UNS Electric is 8.99 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic and legal principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return and allowing a factor for income taxes.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions are universally cited as providing the standards for a fair rate of return. The first is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. **[Emphasis added.]**

It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**. **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In *Simms v. Round Valley Light & Power Company*,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

[1] 294 P.2d 378 (1956).

> "In the Hope case the Court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of UNS Electric' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the *Hope* and *Bluefield* decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that UNS Electric Witness Pignatelli also cites the Hope and Bluefield cases as "guidelines" for evaluating the cost of capital for the Company.

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the component of the capital structure that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. Which methods have you employed in your analyses of the cost of common equity in this proceeding?

A. I have utilized three methodologies to determine UNS Electric's cost of common equity: the DCF, CAPM, and CE methods. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. Why are economic and financial conditions important in determining the costs of capital?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), and the level of inflation. My understanding is that use of the factors is consistent with the Supreme Court's Bluefield decision, which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. What indicators of economic and financial activity have you evaluated in your analyses?

A. I have examined several sets of economic statistics for the period 1975 to present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, and thus makes it possible to assess changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframe of the three prior business cycles and the most current cycle.

A. The three prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present	

Q. Do you have any general observations concerning the changing trends in economic conditions and their impact on costs over this broad period?

A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession in 2001. During the recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., Fed Funds rate) 11 times in 2001 and twice in 2003 in an effort to stimulate the economy.

Q. Please describe recent and current economic and financial conditions and their impact on the costs of capital.

A. Schedule 2 shows several sets of economic data. Page 1 contains general macroeconomic statistics while Pages 2 and 3 contain financial market statistics. Page 1 of Schedule 2 shows that the U.S. economy is currently in the fifth year of an economic expansion. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate. This current expansion has generally been characterized as slower growth, in comparison to prior expansions. This has resulted in lower inflationary pressures and interest rates.

The rate of inflation is also shown on Page 1 of Schedule 2. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. The 2.5 percent rate of inflation in 2006 was similar to the levels since 2000, but was well below the levels of the past thirty years.

Q. What have been the trends in interest rates?

A. Page 2 of Schedule 2 shows several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates then fell substantially in conjunction with inflation rates throughout the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2004 and generally recorded their lowest levels since the 1960s.

This low level of interest rates, in conjunction with the recent strength of the U.S. economy, may create an expectation that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has, since the middle of 2004, increased short-term interest rates on 17 occasions, although each time by only 0.25 percent, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates. Further, the current level of Fed Funds is about the same as the level in existence when the series of reductions began in 2000. Even if long-term rates were to increase moderately, they would still remain well below historical levels.

Q. What have been the trends in common share prices?

A. Page 3 of Schedule 2 shows several series of common stock prices and ratios. These indicate that share prices were basically stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices. During the initial years of the current expansion, however, stock prices were volatile and declined substantially from their highs reached in 1999 and early 2000. Share prices have increased somewhat since 2003 and currently stand at near record high levels.

Q. What conclusions do you draw from this discussion of economic and financial conditions?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models currently produce returns that are lower than was the case in prior years.

V. UNS ELECTRIC' OPERATIONS AND RISKS

Q. Please summarize UNS Electric and its operations.

A. UNS Electric is a public utility that provides electric distribution services to some 93,000 customers in Arizona. UNS Electric was formerly the Arizona electric distribution operations of Citizens Communications Company, prior to its 2003 acquisition by UniSource Energy. When UniSource Energy acquired the Arizona electric and gas assets from Citizens, it formed two operating companies - UNS Electric and UNS Gas.

Q. Please describe Unisource Energy.

A. UniSource Energy is a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), a generation and distribution company that is the second-largest investor-owned utility in Arizona. UniSource Energy also owns UniSource Energy Services ("UES"), which contains UNS Electric and UNS Gas, both of which are distribution companies. It previously owned Millennium Energy Holdings, the parent company of UniSource Energy's unregulated energy business whose principal subsidiary was Global Solar. UniSource Energy presently operates through three primary business segments – TEP, UNS Electric and UNS Gas.

Q. What have been the business segment ratios of Unisource Energy in recent years?

A. This is shown on Schedule 3. As this indicates, as of 2006, UNS Electric accounted for about 12 percent of the revenues of UniSource Energy and about 6 percent of total assets.

Q. What are the current bond ratings of Unisource Energy and TEP?

A. The current ratings of UniSource Energy and TEP are:

	Standard & Poor's	Moody's	Fitch
UniSource Energy Credit Ratings			
Senior Secured Debt	NR	Ba1	NR
Issuer Rating	NR	Ba1	N/A
Tucson Electric Power Credit Ratings			
Senior Secured Debt	BBB-	Baa2	BBB-
Senior Unsecured Debt	B+	Baa3	BB+
Issuer Rating	BB	Baa3	BB

Source: UniSource Energy Web Site.

UNS Electric does not have its own security ratings, and its single debt issue was privately placed in 2003 at the time of the acquisition. The debt of UNS Electric is guaranteed by UES. As such, the debt of UNS Electric is related to the overall credit strength of UniSource Energy.

Q. Did the acquisition of the assets current comprising UNS Electric have any impact on the security ratings of Unisource Energy or TEP?

A. No, it did not. Standard & Poor's, for example, made the following comments in an August 12, 2003 CreditWatch report on TEP:

> Standard & Poor's Ratings Services said today it affirmed its ratings on Tucson Electric Power Co. ('BB' corporate credit rating) and removed them from CreditWatch with negative implications. They were placed on CreditWatch Nov. 8, 2002, reflecting parent UniSource Energy Corp.'s announcement of an agreement to **purchase** the **Arizona electric** and gas **transmission and distribution assets** from Citizens Communications Co. The outlook is stable.
>
> The Aug. 11, 2003, acquisition of **these relatively low-risk, widely scattered regulated assets** for $220 million, **well below the book value** of about $425 million, **bolsters the consolidated business profile** of the UniSource Energy family of companies, and does so with a financing package that **marginally improves the overall financial condition of UniSource Energy**. These assets are subject to regulation by the Arizona Corporation Commission (ACC), as is Tucson Electric, and are structured

> as a wholly owned subsidiary of UniSource Energy called UniSource Energy Services.
>
> The addition of about 77,000 electric customers and 126,000 gas customers represents an increase of about 40% to Tucson Electric's customer base. The acquisition has received strong regulatory support, mainly because rate increases will be limited to only about one-half of what they would have been in the absence of the purchase, as well as because of operational challenges faced by prior management. **[Emphasis added]**

Q. Are you aware that UNS Electric is requesting the inclusion of construction work in process as part of its rate filing?

A. Yes, I am. It is my understanding that UNS Electric is requesting some $10.8 million of Construction Work In Progress ("CWIP") in its request, which results in about $2.1 million of annual revenues to the Company. UNS Electric witness Grant cites the inclusion of CWIP as necessary for the Company to attract capital.

Q. Do you agree that it is necessary for UNS Electric to have CWIP treatment in order for it to attract capital?

A. No, I do not. It has been my general experience that CWIP treatment is generally regarded as a ratemaking practice to be used in situations where a utility has a very large construction program and the company requires the cash treatment in order to manage its construction program and related financing. As such, CWIP is not the norm.

In the case of UNS Electric, I do not believe that it is necessary to provide CWIP treatment in order for this Company to attract capital. As I indicated above, the rating agencies describe the operations of UNS Electric as low risk. It is further apparent that UNS Electric receives its financing based on the credit quality of UniSource Energy and/or UES, not based on the situation of the Company itself. In summary, I do not believe it is necessary for UNS Electric to receive CWIP treatment in order for it to attract capital.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the pool of dollars represented by the capital structure finance the rate base.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. How is UNS Electric financed?

A. UNS Electric is a subsidiary of UES, which in turn is a subsidiary of UniSource Energy. UNS Electric has one series of long-term notes outstanding, which is guaranteed by UES.

Q. How have you evaluated the capital structure of UNS Electric and Unisource Energy?

A. I have first examined the recent capital structure ratios of UNS Electric and UniSource Energy.

UNS Electric' capital structure did not exist until 2003, when UniSource Energy created a subsidiary from the electric distribution assets in Arizona, as acquired from Citizens Communications. As is shown on Page 1 of Schedule 4, the common equity ratios of UNS Electric have been as follows:

	Including S-T Debt	Excluding S-T Debt
2003	37.6%	37.9%
2004	40.3%	40.5%
2005	45.2%	45.4%
2006	45.0%	45.1%

This indicates a rising level of common equity over this period.

Q. What are the capital structure ratios of Unisource Energy?

A. These are shown on Page 2 of Schedule 4. These common equity ratios of UniSource Energy, on a consolidated basis, are summarized below:

	Including S-T Debt	Excluding S-T Debt
2002	28.8%	28.8%
2003	30.2%	30.2%
2004	31.6%	31.6%
2005	33.6%	33.7%
2006	34.9%	35.8%

These common equity ratios are substantially less than those of UNS Electric.

Q. How do the capital structures of UNS Electric compare to the other utility subsidiaries of Unisource Energy?

A. This is shown on Page 3 of Schedule 4. As this indicates, UNS Electric and UNS Gas have higher common equity ratios than TEP and UniSource Energy.

Q. How do these capital structures compare to those of investor-owned electric and combination gas/electric utilities?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the two groups of electric utilities covered by AUS Utility Reports. These are:

Year	Electric	Combination Gas And Electric
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%
2006	45%	44%

These common equity ratios are generally similar to those of UNS Electric in 2006.

Q. What capital structure ratios has UNS Electric requested in this proceeding?

A. The Company requests use of its June 30, 2007 capital structure ratios. This contains a requested common equity ratio of 48.85 percent.

Q. What capital structure do you propose to use in this proceeding?

A. I propose use of the actual capital structure ratios of UNS Electric as of June 30, 2006. This capital structure reflects the test period per books ratios of the Company. This is very similar to the June 30, 2007 capital structure proposed by UNS Electric.

Q. What is the cost rate of long-term debt in the company's application?

A. The Company's filing cites, as of June 30, 2006, a cost of long-term debt of 8.16 percent and a cost of short-term debt of 6.36 percent. I use these rates in my cost of capital analyses.

Q. Can the cost of common equity be determined with the same degree of precision as the cost of debt?

A. No. The cost rate of debt is largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for UNS Electric?

A. UNS Electric is not a publicly-traded company. Consequently, it is not possible to directly apply cost of equity models to this entity. Its ultimate parent company, UniSource Energy, is publicly-traded. As a result, it is possible to conduct direct analyses of its cost of common equity, although this company's recent financial situation and diversified nature make its results of limited value. Consequently, it is necessary to analyze groups of comparison or "proxy" companies as a substitute for UNS Electric to determine its cost of common equity.

I have examined two such groups for comparison to UNS Electric. The first group of proxy companies I examined is a group of nine electric and combination gas electric companies, similar to UniSource Energy, selected based on the criteria shown on my Schedule 6. Second is the group of eight combination gas and electric utilities used by UNS Electric witness Grant in his cost of capital analyses.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theory and methodological basis of the discounted cash flow model?

A. The discounted cash flow model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)
P = current price
D = current dividend rate
G = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is a dividend growth variant, which is expressed as follows:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (March-May 2007). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock.

A wide array of indicators exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2002-2006 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) (per Value Line);
3. 2007, 2008, and 2010-2012 projections of earnings retention growth (per Value Line);
4. 2004-2006 to 2010-2012 projections of EPS, DPS, and BVPS (per Value Line); and,
5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your initial DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	Mean	Median	High[2]
Comparison Group	8.5%	8.6%	11.7%
Grant Group	8.3%	8.3%	11.5%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

The DCF results in Schedule 7 indicate average (mean and median) DCF cost rates of about 8.5 percent. The highest DCF rates (i.e., using the single highest growth rates only) are about 11½ percent. This indicates a broad range of DCF results of 8.5 percent to 11.5 percent.

[2] Using only the highest growth rate.

Q. What do you conclude from your DCF analyses?

A. Based upon my analyses, I believe a range of 9.5 percent to 10.5 percent represents the current DCF cost of equity for the proxy groups. This is approximated by the middle of the DCF calculations for the groups examined in the previous analysis. I recommend a 9.5 percent to 10.5 percent (10.0 percent mid-point) for UNS Electric.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the capital asset pricing model.

A. The Capital Asset Pricing Model ("CAPM") is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity
R_f = risk free rate
R_m = return on market
β = beta
R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple risk premium method does not, but rather the simple risk premium method assumes the same cost of equity for all companies exhibiting similar bond ratings.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. What rate did you use for the risk-free rate?

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three month average yield (March-May 2007) for 20-year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 4.91 percent.

Q. What is beta and what betas did you employ in your CAPM

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2005 (all available years reported by S&P). The average return on equity for the S&P 500 group over the 1978-2005 period is 14.09 percent. This Schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.2 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2005 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.4%	5.0%

I conclude from this that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations using the risk premium. The results are:

	Mean	Median
Comparison Group	10.6%	10.5%
Grant Group	10.2%	9.9%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of about 10 percent to 10.5 percent for the two groups of comparison utilities.

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's original book value (reflected in the book common equity in its balance sheet) to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. How have you employed the CE methodology in your analysis of UNS Electric' common equity cost?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution of book value. As a result, maintenance of a stock price above book value is one measure of the fairness of a utility's authorized cost of equity.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my comparable earnings analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my comparable earnings analysis uses prospective returns and thus is not backward looking.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2006 (i.e., last fifteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2006 (the last five years - the average length of a business cycle) and 1992-2001 (the most recent complete business cycle).

Q. Please describe your CE analysis.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

	Historic		Prospective
Group	ROE	M/B	ROE
Comaprison Group	9.0-10.2%	153-154%	10.6-10.7%
Grant Group	9.5-10.6%	148-153%	9.5-10.3%

These results indicate that historic returns of 9.0-10.6 percent have been adequate to produce market-to-book ratios of 148-154 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2007, 2008, and 2010-2012 are within a range of 9.5 percent to 10.7 percent for the utility groups. These relate to 2006 market-to-book ratios of 151 percent or higher.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past fourteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 12.2 to 14.7 percent with market-to-book ratios ranging from 299 to 341 percent.

Q. How can the above information be used to estimate the cost of equity for UNS Electric?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industries with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is slightly more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 10 percent. Recent returns of 9.0-10.6 percent have resulting in market-to-book ratios of 148 and greater. Prospective returns of 9.5 to 10.7 percent have been accompanied by market-to-book ratios of over 151 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.5-10.5% (10.0% mid-point)
Capital Asset Pricing Model	10.0-10.5% (10.25% mid-point)
Comparable Earnings	10.0%

My overall conclusion from these results is an overall range of 9.5 percent to 10.5 percent, which focuses on the respective ranges of my individual model findings. Focusing on the respective mid-points, the range is 10 percent to 10.25 percent. I conclude that the cost of equity rate for UNS Electric is in the range from 9.5 percent to 10.5 percent (mid-point 10.0 percent).

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for UNS Electric?

A. Schedule 13 reflects the total cost of capital for the Company using the June 30, 2006 capital structure and costs of long-term and short term debt, and my common equity cost recommendations. The resulting total cost of capital is a range of 8.74 percent to 9.23 percent, with a mid-point of 8.99 percent. I recommend that this 8.99 total cost of capital be established for UNS Electric.

Q. Does your cost of capital recommendation provide the company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if UNS Electric earned the mid-point of my cost of capital recommendation. As the results indicate, the mid-point of my recommended range would produce a coverage level within the benchmark range for an A rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the testimony and cost of capital recommendation of UNS Electric witness Kentton C. Grant?

A. Yes, I have. Mr. Grant is recommending the following cost of capital for UNS Electric:

Capital Item	Percent	Cost	Weighted Cost
Short-term Debt	3.97%	6.36%	0.25%
Long-term Debt	47.18%	8.22%	3.88%
Common Equity	48.85%	11.80%	5.76%
Total	100.0%		9.89%

Mr. Grant's 11.8 percent cost of common equity recommendation is derived as follows:

	Range	Median
DCF	9.7-10.5%	10.4%
CAPM	9.8-11.2%	10.5%

Q. Do you have any comments concerning Mr. Grant's DCF analysis and recommendations?

A. I note that Mr. Grant's 9.7-10.5 percent DCF conclusions do not vary significantly from my DCF conclusions of 9.0-10.5 percent. As a result, I have no further comments on his DCF analyses and conclusions at this time.

Q. What are your comments concerning Mr. Grant's CAPM analysis and conclusions?

A. Mr. Grant's CAPM analysis takes the following form:

Risk-free rate	=	4.84%	=	September, 2006 20-yr. T bonds Yield
Risk Premium	=	7.1%	=	Ibbotson risk premium
Beta	=		=	Value Line

My primary disagreement is with Mr. Grant's risk premium input.

My disagreements with Mr. Grant's risk premium is his exclusive reliance on the 1926-2005 arithmetic average differences between large company stocks (i.e., S&P 500) and long-term Treasury bonds. As I indicated earlier in my testimony, it is preferable to use multiple sources of risk premium measures, as I have done. Mr. Grant's 7.1 percent risk premium used only arithmetic returns, and ignores geometric (compound) returns in deriving the risk premium component of the CAPM. This is not proper. What is important is not what Mr. Grant and I believe, but what investors rely upon in making investment decisions. It is apparent that investors have access to both types of returns, and correspondingly use both types of returns, when they make investment decisions.

In fact, it is noteworthy that mutual fund investors regulatory receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns. Based on this, I find it difficult to accept Mr. Grant's position that only arithmetic returns are considered by investors, and, thus, only arithmetic returns are appropriate in a CAPM context.

Q. Does Mr. Grant use value line information in his cost of capital analyses?

A. Yes, he does.

Q. Do the value line reports cited in his testimony show historic growth rates for the electric utilities?

A. Yes, they do.

Q. Do these value line reports show historic returns on an arithmetic basis?

A. No, they do not.

Q. Do the value line reports show historic returns on a geometric, or compound growth rate basis?

A. Yes, they do. As a result, any investor reviewing Value Line, as Mr. Grant does, would be using geometric growth rates, not arithmetic growth rates.

Q. Is it you position that only geometric growth rates be used?

A. No. I believe that both arithmetic and geometric growth rates should be used. This is the case since investors have access to both and presumably use both.

Q. Mr. Grant also makes an adjustment for the size of UNS Electric, is this proper?

A. No, it is not. UNS Electric does not raise its own equity capital (as it comes from UniSource Energy) and its debt is guaranteed by UES. As a result, it is these entities that are evaluated by investors and it is the size of these entities that investors consider. I note in this regard, that UniSource Energy as some $1.4 billion market value of equity and Value Line describes this Company as a "Mid Cap" stock.

Q. Mr. Grant also cites the growth of UNS Electric as a risk indicator. Do you agree with this?

A. No, I do not. My earlier testimony cites a S&P analysis of UniSource Energy that describes the UNS Electric and UNS Energy components as "low-risk."

Q. Mr. Grant also claims, on page 23, that his 11.8 percent recommendation is "reasonable" in comparison to the authorized returns on equity for other electric utilities. Do you have any response to this?

A. Yes, I do. The source Mr. Grant is quoting – Regulatory Research Associates – compiles the authorized returns on equity for utilities, including electric utilities. I note the following trend in authorized returns on equity over the past several years:

2000	11.43%
2001	11.09%
2002	11.16%
2003	10.99%
2004	10.75%
2005	10.54%
2006	10.36%

It is apparent from this that average authorized returns on equity have not been as high as 11.8 percent since at least 2000 and they have not been as high as 11.0 percent since 2002. It is also apparent that the average level of authorized return on equity has declined in each year since 2002 a period of four years. It is thus apparent that Mr. Grant's 11.8 percent requested return on equity ignores both the trend and level of authorized returns.

Q. Do you have any comments on Mr. Grant's recommendation for UNS Electric?

A. Yes, I do. Mr. Grant's DCF and CAPM findings can be summarized as follows:

	DCF	CAPM	Recommendation
Low End	9.7%	9.8%	9.7%
High End	10.5%	11.2%	11.2%
Mid-Point	10.1%	10.5%	

It is apparent that, had Mr. Grant focused on the respective mid-points of his DCF and CAPM ranges, his recommendation should have been a range of 10.1 percent to 10.8 percent, which is similar to my recommended range. However, his recommendation instead focuses on the top end of the CAPM range, or 11.2 percent, which is the CAPM result for a single company. Further, as is evident from Mr. Grant's Exhibit KCG-5, the average CAPM result excluding Cleco Corp. (whose CAPM result is 13.7 percent, or 250 basis points higher than his next highest CAPM rate – 11.2 percent) is 10.5 percent. This 10.5 percent is also the median CAPM result excluding Cleco. In addition, had Mr. Grant more appropriately focused on the median results of his DCF and CAPM models, his conclusions would have been 10.35 percent to 10.5 percent and had he focused on the average results his conclusions would have been 10.2 percent to 10.5 percent. Again, his 11.2 percent upper end represents the CAPM result of a single company, which ultimately drives his 9.7 percent to 11.2 percent recommendation.

In addition, Mr. Grant compounds his over-statement of the cost of equity for UNS Electric by adding sixty basis points to his 9.7 percent to 11.2 percent range to reflect the "decidedly riskier" nature of UNS Electric's operations relative to the comparable group. This sixty basis point adjustment is based on the differential in yields between Triple-B utility bonds and Double-B utility bonds, which implicitly and incorrectly assumes that UNS Electric is a non-investment grade company.

Finally, Mr. Grant's 11.8 percent recommendation for UNS Electric is based on the upper end of his modified recommended range (i.e., 10.3 percent to 11.8 percent), which in essence means that his recommendation is based on the CAPM results for a single company, adjusted upward by sixty basis points based on an erroneous assumption that UNS Electric is a non-investment grade company.

XIV. UNS ELECTRIC PROPOSAL TO APPLY COST OF CAPITAL TO FAIR VALUE RATE BASE

Q. What is your understanding of UNS Gas' proposal to apply the company's cost of captial to a fair value rate base?

A. According to Schedule A-1, UNS Electric is proposing that the total cost of capital for the Company be applied to the "fair value" of the Company's rate base. This request is apparently being made in response to a recent Arizona Court of Appeals decision regarding Chaparral City Water Company. I note, on the other hand, that no UNS Electric witness appears to be endorsing this ratemaking treatment. In particular, Mr. Pignatelli and Mr. Grant, the two witnesses who address the Company's cost of capital, do not cite this.

Q. Have you reviewed this decision and do you have any comments on your understanding of its implications for this case?

A. Yes, I do. My "non-legal understanding" of this decision is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree with UNS Electric that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

My "non-legal understanding" of the Court decision indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base' and thus was appropriately applied here to the OCRB." The decision went on to state "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether the cost of capital is consistent with a fair value rate base?

A. Yes, I do. It is my personal experience, based upon over 35 years of providing cost of capital testimony, that the entire concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet. From a financial, as well as regulatory, perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The "excess" of fair value rate base over original cost rate base is not financed with investor-supplied funds and, indeed, the excess is not financed at all. As a result, the cost of capital cannot be applied to the fair value rate base since there is no financial link between the two concepts.

Q. Why is it important that there be a link between the concepts of rate case and cost of capital?

A. This link is important since financial theory, as well as regulatory precedent, indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world) the link between cost of capital and rate base satisfies this financial and regulatory objective.

Q. Based on your experience as a cost of capital witness over the past 35 years, do you have a proposed solution for the commission to account for the use of a fair value rate base in setting rates for UNS Electric?

A. Yes, I do. Since the differential between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate to assume that this excess has no cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the excess of fair value rate base over the original cost rate base. Such a procedure would still provide for a return being earned on all investor-supplied funds and thus be consistent with financial and regulatory standards.

Q. Has the staff made such a proposal in this proceeding?

A. Yes, it has. Staff witness Ralph Smith has re-cast my cost of capital calculation in a fashion that incorporates my surrebuttal position. As this indicates, the "fair value cost of capital" for UNS Electric is 7.01 percent.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's

Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,
Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.7%	4.2%	2.7%	2.9%
2000	3.7%	4.5%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	0.0%	5.8%	2.4%	1.2%
2003	2.5%	1.1%	6.0%	1.9%	4.0%
2004	3.9%	2.5%	5.5%	3.3%	4.2%
2005	3.2%	3.2%	5.1%	3.4%	5.4%
2006	3.3%	3.9%	4.6%	2.5%	1.1%
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.7%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.7%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.2%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	3.6%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.8%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.8%	2.7%	5.0%	8.8%	14.0%
4th Qtr.					
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.6%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	2.0%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	2.5%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	1.3%	2.6%	4.5%	4.8%	2.8%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.94%	4.60%		5.61%	5.80%	6.04%
Dec		4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
			1975 - 1982 Cycle		
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
			1983 - 1991 Cycle		
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
			1992 - 2001 Cycle		
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
			Current Cycle		
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	
4th Qtr					
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.88%
3rd Qtr.	1,288.40	2,141.97	11,584.69	1.91%	5.88%
4th Qtr	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%

Source: Council of Economic Advisors, Economic Indicators, various issues.

UNISOURCE ENERGY
SEGMENT FINANCIAL INFORMATION
2003 - 2005
($millions)

Segment	Operating Revenue	Net Income	Total Assets
		2003	
Tucson Electric Power	$852 87.6%	$129 113.2%	$2,767 88.6%
UNS Gas 1/	$47 4.8%	$1 0.9%	$185 5.9%
UNS Electric 1/	$56 5.8%	$2 1.8%	$125 4.0%
Global Solar	$2 0.2%	-$7 -6.1%	$26 0.8%
UniSource Energy Consolidated	$973	$114	$3,123
		2004	
Tucson Electric Power	$889 76.0%	$46 100.0%	$2,742 86.3%
UNS Gas	$129 11.0%	$6 13.0%	$201 6.3%
UNS Electric	$144 12.3%	$4 8.7%	$135 4.3%
Global Solar	$5 0.4%	-$5 -10.9%	$20 0.6%
UniSource Energy Consolidated	$1,169	$46	$3,176
		2005	
Tucson Electric Power	$937 76.2%	$48 104.3%	$2,575 82.3%
UNS Gas	$138 11.2%	$5 10.9%	$233 7.5%
UNS Electric	$150 12.2%	$5 10.9%	$161 5.1%
Global Solar	$5 0.4%	-$7 -15.2%	$20 0.6%
UniSource Energy Consolidated	$1,230	$46	$3,127
		2006	
Tucson Electric Power	$998 75.8%	$67 100.0%	$2,623 82.3%
UNS Gas	$162 12.3%	$4 6.0%	$253 7.9%
UNS Electric	$160 12.1%	$5 7.5%	$195 6.1%
UniSource Energy Consolidated	$1,317	$67	$3,187

1/ 2003 figures for UNS Gas and UNS Electric are for period August 11 through December 31.

Note: Totals may not add to 100.0% due to "All Others" and "Reconciling Adjustments."

Source: UniSource Energy Annual Report.

UNS ELECTRIC
CAPITAL STRUCTURE RATIOS
2003 - 2006
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$36.6	$60.0	$0.7
	37.6%	61.7%	0.7%
	37.9%	62.1%	
2004	$40.9	$60.0	$0.6
	40.3%	59.1%	0.6%
	40.5%	59.5%	
2005	$49.9	$60.0	$0.5
	45.2%	54.3%	0.5%
	45.4%	54.6%	
2006	$64.9	$79.0	$0.4
	45.0%	54.7%	0.3%
	45.1%	54.9%	

Note: Percentages may not total 100.0% due to rounding.

Debt figures exclude capital lease obligations.

Source: Response to STF 4.8.

UNISOURCE ENERGY
CAPITAL STRUCTURE RATIOS
2002 - 2006
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2002	$456,640	$0	$1,128,963	$0
	28.8%	0.0%	71.2%	0.0%
	28.8%	0.0%	71.2%	
2003	$556,472	$0	$1,286,320	$0
	30.2%	0.0%	69.8%	0.0%
	30.2%	0.0%	69.8%	
2004	$580,718	$0	$1,257,595	$0
	31.6%	0.0%	68.4%	0.0%
	31.6%	0.0%	68.4%	
2005	$616,741	$0	$1,212,420	$5,000
	33.6%	0.0%	66.1%	0.3%
	33.7%	0.0%	66.3%	
2006	$654,149	$0	$1,171,170	$50,000
	34.9%	0.0%	62.5%	2.7%
	35.8%	0.0%	64.2%	

Note: Percentages may not total 100.0% due to rounding.

Source: UniSource Energy Annual Report.

UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
December 31, 2006
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource Energy	$654.1	$1,171.2	$50.0
Consolidated	34.9%	62.5%	2.7%
	35.8%	64.2%	
Tucson Electric	$554.7	$821.2	$0.0
Power Company	40.3%	59.7%	0.0%
	40.3%	59.7%	
UniSource Energy	$149.4	$179.0	$0.0
Services	45.5%	54.5%	0.0%
	45.5%	54.5%	
UNS Electric	$64.9	$79.0	$0.0
	45.1%	54.9%	0.0%
	45.1%	54.9%	
UNS Gas	$84.2	$100.0	$0.0
	45.7%	54.3%	0.0%
	45.7%	54.3%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 4.8.

Exhibit___(DCP-1)
Schedule 5

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%
2006	45%	44%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 6

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ S&P Bond Rating	S&P Stock Ranking
Unisource Energy	$1,400	85%	25%	3	BBB- / BAA2	B
Comparison Group*						
Avista Corp.	$1,200	50%	41%	3	BBB- / BAA3	B
Cleco Corp.	$1,500	96%	52%	3	BBB / BAA1	B+
DPL, Inc.	$3,400	100%	38%	3	BBB / NR	B+
Hawaiian Electric	$2,200	84%	53%	2	BBB / BAA2	B+
Northeast Utilities	$4,500	77%	35%	3	BBB / BAA1	B
Pepco Holdings, Inc.	$5,100	58%	42%	3	BBB+ / BAA1	B
PG&E Corp.	$1,900	70%	50%	2	BBB / BAA1	B
PNM Resources	$2,100	79%	42%	2	BBB / BAA2	B+
Puget Energy, Inc.	$3,000	61%	46%	3	BBB / BAA2	B

* Selected using following criteria:
Market cap of $1 billion to $8 billion.
Electric Revenues of 40% or greater.
Common Equity Ratio of 35% or greater.
Value Line Safety of 1, 2 or 3.
S&P bond ratings of BBB and Moody's bond ratings of Baa.
S&P stock ranking of B or B+.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	March-May 2007 Stock Prices HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Avista Corp.	$0.60	$24.89	$22.88	$23.89	2.5%
Cleco Corp.	$0.90	$29.20	$24.83	$27.02	3.3%
DPL, Inc.	$1.04	$32.72	$29.58	$31.15	3.3%
Hawaiian Electric	$1.24	$26.73	$24.50	$25.62	4.8%
Northeast Utilities	$0.75	$33.62	$28.20	$30.91	2.4%
Pepco Holdings, Inc.	$1.04	$30.71	$25.85	$28.28	3.7%
PG&E Corp.	$1.44	$52.17	$45.10	$48.64	3.0%
PNM Resources	$0.92	$34.28	$28.50	$31.39	2.9%
Puget Energy, Inc.	$1.00	$26.91	$24.00	$25.46	3.9%
Average					**3.3%**
Grant Combination Gas and Electric Utilities Group					
CH Energy Group, Inc.	$2.16	$50.78	$45.93	$48.36	4.5%
Cleco Corp.	$0.90	$29.20	$24.83	$27.02	3.3%
Hawaiian Electric	$1.24	$26.73	$24.50	$25.62	4.8%
MGE Energy Inc.	$1.39	$37.02	$33.05	$35.04	4.0%
Northeast Utilities	$0.75	$33.62	$28.20	$30.91	2.4%
NSTAR	$1.30	$37.37	$33.36	$35.37	3.7%
Puget Energy, Inc.	$1.00	$26.91	$24.00	$25.46	3.9%
UIL Holdings	$1.73	$37.01	$32.80	$34.91	5.0%
Average					**4.0%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2002	2003	2004	2005	2006	Average	2007	2008	2010-12	Average
Comparison Group										
Avista Corp.	1.2%	3.4%	1.4%	2.4%	4.9%	2.7%	3.5%	4.0%	2.0%	3.2%
Cleco Corp.	5.6%	3.5%	3.9%	4.1%	3.0%	4.0%	2.0%	2.5%	3.0%	2.5%
DPL, Inc.	0.0%	2.2%	9.8%	0.8%	9.0%	4.4%	10.0%	9.0%	6.5%	8.5%
Hawaiian Electric	4.3%	3.9%	1.1%	1.5%	0.7%	2.3%	0.5%	1.5%	3.5%	1.8%
Northeast Utilities	3.2%	3.7%	1.6%	1.5%	5.0%	3.0%	4.0%	4.0%	4.0%	4.0%
Pepco Holdings, Inc.	5.3%	2.0%	2.5%	2.4%	1.5%	2.7%	3.0%	4.0%	5.5%	4.2%
PG&E Corp.	0.0%	18.5%	10.3%	7.7%	6.6%	8.6%	6.0%	5.5%	4.5%	5.3%
PNM Resources	3.1%	3.0%	4.5%	4.3%	3.7%	3.7%	4.0%	3.5%	3.0%	3.5%
Puget Energy, Inc.	1.3%	2.1%	2.8%	2.9%	3.0%	2.4%	3.0%	3.5%	4.0%	3.5%
Average						**3.8%**				**4.1%**
Grant Combination Gas and Electric Utilities Group										
CH Energy Group, Inc.	0.0%	2.0%	1.7%	2.0%	1.5%	1.4%	1.5%	1.5%	2.0%	1.7%
Cleco Corp.	5.6%	3.5%	3.9%	4.1%	3.0%	4.0%	2.0%	2.5%	3.0%	2.5%
Hawaiian Electric	4.3%	3.9%	1.1%	1.5%	0.7%	2.3%	0.5%	1.5%	3.5%	1.8%
MGE Energy Inc.	2.6%	2.5%	2.3%	2.5%	3.5%	2.7%	4.0%	4.0%	3.0%	3.7%
Northeast Utilities	3.2%	3.7%	1.6%	1.5%	5.0%	3.0%	4.0%	4.0%	4.0%	4.0%
NSTAR	5.2%	5.2%	4.9%	4.7%	2.5%	4.5%	5.0%	5.5%	6.0%	5.5%
Puget Energy, Inc.	1.3%	2.1%	2.8%	2.9%	3.0%	2.4%	3.0%	3.5%	4.0%	3.5%
UIL Holdings	0.6%	0.0%	0.0%	0.0%	0.5%	0.2%	0.5%	1.0%	1.5%	1.0%
Average						**2.6%**				**3.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates EPS	DPS	BVPS	Average	Est'd '04-'06 to '10-'12 Growth Rates EPS	DPS	BVPS	Average
Comparison Group								
Avista Corp.	0.5%	2.5%	3.5%	2.2%	12.0%	12.5%	5.0%	9.8%
Cleco Corp.	1.0%	2.0%	4.0%	2.3%	4.0%	4.0%	6.5%	4.8%
DPL, Inc.	-1.0%	0.5%	-1.0%	-0.5%	8.0%	7.5%	5.0%	6.8%
Hawaiian Electric	-1.0%	0.0%	2.0%	0.3%	4.0%	0.0%	0.5%	1.5%
Northeast Utilities	0.0%	30.5%	3.0%	11.2%	8.5%	6.5%	1.5%	5.5%
Pepco Holdings, Inc.	-1.0%	0.0%	0.5%	-0.2%	8.0%	3.0%	3.0%	4.7%
PG&E Corp.	0.0%	-1.5%	9.5%	2.7%	4.0%	0.0%	6.0%	3.3%
PNM Resources	-2.5%	7.5%	4.5%	3.2%	4.5%	8.0%	5.5%	6.0%
Puget Energy, Inc.	-4.5%	-11.5%	1.5%	-4.8%	6.0%	3.0%	4.0%	4.3%
Average				**1.8%**				**5.2%**
Grant Combination Gas and Electric Utilities Group								
CH Energy Group, Inc.	-1.5%	0.0%	2.0%	0.2%	1.0%	0.5%	1.5%	1.0%
Cleco Corp.	1.0%	2.0%	4.0%	2.3%	4.0%	4.0%	6.5%	4.8%
Hawaiian Electric	-1.0%	0.0%	2.0%	0.3%	4.0%	0.0%	0.5%	1.5%
MGE Energy Inc.	2.0%	1.0%	6.5%	3.2%	6.0%	50.0%	7.0%	21.0%
Northeast Utilities	0.0%	30.5%	3.0%	11.2%	8.5%	6.5%	1.5%	5.5%
NSTAR	4.0%	1.0%	2.0%	2.3%	7.5%	8.0%	6.0%	7.2%
Puget Energy, Inc.	-4.5%	-11.5%	1.5%	-4.8%	6.0%	3.0%	4.0%	4.3%
UIL Holdings	-9.0%	0.0%	2.0%	-2.3%	6.0%	0.0%	2.0%	2.7%
Average				**1.5%**				**6.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Avista Corp.	2.6%	2.7%	3.2%	2.2%	9.8%	5.5%	4.7%	7.2%
Cleco Corp.	3.4%	4.0%	2.5%	2.3%	4.8%	12.0%	5.1%	8.6%
DPL, Inc.	3.5%	4.4%	8.5%		6.8%	10.0%	7.4%	10.9%
Hawaiian Electric	4.9%	2.3%	1.8%	0.3%	1.5%	3.0%	1.8%	6.7%
Northeast Utilities	2.5%	3.0%	4.0%	11.2%	5.5%	12.0%	7.1%	9.7%
Pepco Holdings, Inc.	3.8%	2.7%	4.2%		4.7%	10.0%	5.4%	9.2%
PG&E Corp.	3.0%	8.6%	5.3%	2.7%	3.3%	8.0%	5.6%	8.6%
PNM Resources	3.0%	3.7%	3.5%	3.2%	6.0%	10.0%	5.3%	8.3%
Puget Energy, Inc.	4.0%	2.4%	3.5%		4.3%	4.0%	3.6%	7.6%
Average	3.4%	3.8%	4.1%	3.6%	5.2%	8.3%	5.1%	**8.5%**
Median								**8.6%**
Composite		7.2%	7.5%	7.0%	8.6%	**11.7%**	8.5%	
Grant Combination Gas and Electric Utilities Group								
CH Energy Group, Inc.	4.5%	1.4%	1.7%	0.2%	1.0%		1.1%	5.6%
Cleco Corp.	3.4%	4.0%	2.5%	2.3%	4.8%	12.0%	5.1%	8.6%
Hawaiian Electric	4.9%	2.3%	1.8%	0.3%	1.5%	3.0%	1.8%	6.7%
MGE Energy Inc.	4.1%	2.7%	3.7%	3.2%	21.0%		7.6%	11.8%
Northeast Utilities	2.5%	3.0%	4.0%	11.2%	5.5%	12.0%	7.1%	9.7%
NSTAR	3.8%	4.5%	5.5%	2.3%	7.2%	6.0%	5.1%	8.9%
Puget Energy, Inc.	4.0%	2.4%	3.5%		4.3%	4.0%	3.6%	7.6%
UIL Holdings	5.0%	0.2%	1.0%		2.7%	8.0%	3.0%	8.0%
Average	4.0%	2.6%	3.0%	3.3%	6.0%	7.5%	4.3%	**8.3%**
Median								**8.3%**
Composite		6.6%	7.0%	7.3%	10.0%	**11.5%**	8.3%	

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.26%	5.11%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
Average			**14.09%**	**7.90%**	**6.19%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	MARKET RETURN	CAPM RATES
Comparison Group				
Avista Corp.	4.91%	0.95	5.90%	10.5%
Cleco Corp.	4.91%	1.30	5.90%	12.6%
DPL, Inc.	4.91%	0.95	5.90%	10.5%
Hawaiian Electric	4.91%	0.75	5.90%	9.3%
Northeast Utilities	4.91%	0.90	5.90%	10.2%
Pepco Holdings, Inc.	4.91%	0.90	5.90%	10.2%
PG&E Corp.	4.91%	1.20	5.90%	12.0%
PNM Resources	4.91%	0.95	5.90%	10.5%
Puget Energy, Inc.	4.91%	0.85	5.90%	9.9%
Average				**10.6%**
Median				**10.5%**
Grant Combination Gas and Electric Utilities Group				
CH Energy Group, Inc.	4.91%	0.85	5.90%	9.9%
Cleco Corp.	4.91%	1.30	5.90%	12.6%
Hawaiian Electric	4.91%	0.75	5.90%	9.3%
MGE Energy Inc.	4.91%	0.80	5.90%	9.6%
Northeast Utilities	4.91%	0.90	5.90%	10.2%
NSTAR	4.91%	0.80	5.90%	9.6%
Puget Energy, Inc.	4.91%	0.85	5.90%	9.9%
UIL Holdings	4.91%	0.95	5.90%	10.5%
Average				**10.2%**
Median				**9.9%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average	2007	2008	2010-12
Comparison Group																				
Avista Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.7%	4.5%	8.9%	10.4%	5.8%	6.5%	7.5%	8.0%
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.5%	13.5%	11.7%	8.0%	8.0%	10.0%
DPL, Inc.	13.3%	14.5%	15.1%	15.2%	15.5%	15.4%	14.9%	15.2%	18.6%	26.5%	11.3%	15.7%	22.7%	12.2%	21.4%	16.4%	16.7%	25.5%	24.0%	18.5%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	11.0%	10.3%	9.5%	10.0%	12.0%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	0.0%	3.8%	4.8%	8.5%	8.5%	8.5%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.2%	11.0%	8.2%	8.5%	9.5%	11.0%
PG&E Corp.	13.6%	11.9%	13.9%	14.4%	10.4%	7.5%	8.9%	11.2%	-67.5%	30.1%	-22.1%	20.9%	13.8%	11.7%	13.7%	5.4%	7.6%	12.0%	12.0%	10.5%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	8.4%	10.0%	7.6%	8.0%	8.0%	7.5%
Puget Energy, Inc.	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	8.1%	10.4%	7.9%	8.5%	8.5%	9.5%
Average	11.5%	11.4%	11.9%	11.8%	10.3%	9.3%	10.0%	8.5%	2.3%	15.0%	5.5%	10.5%	10.3%	8.9%	9.6%	**10.2%**	**9.0%**	**10.6%**	**10.7%**	**10.6%**
Composite																**10.2%**	**9.0%**			
Grant Combination Gas and Electric Utilities Group																				
CH Energy Group, Inc.	11.0%	11.1%	10.7%	10.7%	11.3%	10.9%	10.4%	10.2%	10.5%	10.4%	7.0%	9.1%	8.7%	8.9%	8.4%	10.7%	8.4%	8.0%	8.0%	8.5%
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.5%	13.5%	11.7%	8.0%	8.0%	10.0%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	11.0%	10.3%	9.5%	10.0%	12.0%
MGE Energy Inc.	13.1%	13.3%	13.1%	12.5%	7.1%	12.5%	12.2%	13.0%	14.2%	13.1%	13.2%	12.5%	11.4%	9.4%	12.2%	12.4%	11.8%	12.0%	12.0%	10.5%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	0.0%	3.8%	4.8%	8.5%	8.5%	8.5%
NSTAR	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	13.2%	12.1%	13.5%	13.5%	14.0%	15.0%
Puget Energy, Inc.	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	8.1%	10.4%	7.9%	8.5%	8.5%	9.5%
UIL Holdings	10.8%	10.4%	10.9%	11.8%	10.1%	10.4%	9.5%	11.5%	12.8%	12.1%	8.9%	6.1%	7.5%	5.2%	8.3%	11.0%	7.2%	8.0%	8.5%	8.0%
Average	12.0%	11.2%	11.6%	11.5%	9.5%	8.9%	9.8%	9.3%	10.8%	11.5%	10.3%	9.8%	9.5%	9.0%	8.6%	**10.6%**	**9.5%**	**9.5%**	**9.7%**	**10.3%**
Composite																**10.6%**	**9.5%**			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average
Comparison Group																	
Avista Corp.	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	117%	136%	163%	109%
Cleco Corp.	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	181%	161%
DPL, Inc.	177%	206%	196%	213%	214%	221%	231%	215%	314%	422%	321%	235%	263%	320%	382%	241%	304%
Hawaiian Electric	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	147%	171%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	0%	118%	82%
Pepco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	130%	150%	115%
PG&E Corp.	168%	175%	142%	134%	115%	123%	152%	135%	179%	136%	149%	203%	196%	179%	208%	146%	187%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	134%	96%	119%
Puget Energy, Inc.	149%	146%	112%	119%	130%	155%	170%	146%	143%	143%	126%	129%	137%	133%	129%	141%	131%
Average	153%	157%	136%	140%	143%	145%	157%	146%	186%	173%	143%	138%	156%	165%	164%	**154%**	**153%**
Composite																**154%**	**153%**
Grant Combination Gas and Electric Utilities Group																	
CH Energy Group, Inc.	123.2%	133.1%	106.6%	111.7%	114.1%	135.3%	154.6%	132.9%	124.6%	141.0%	152.2%	147.1%	149.3%	145.9%	154.0%	128%	150%
Cleco Corp.	177.3%	174.9%	156.2%	162.2%	167.8%	170.8%	182.5%	172.3%	222.8%	224.3%	154.1%	134.5%	176.9%	176.6%	162.5%	181%	161%
Hawaiian Electric	170.8%	153.9%	141.2%	149.1%	147.0%	147.1%	154.1%	131.8%	126.7%	145.1%	153.3%	150.9%	178.8%	181.2%	191.8%	147%	171%
MGE Energy Inc.	189.0%	196.5%	188.9%	183.3%	203.5%	188.9%	196.5%	176.5%	172.0%	197.0%	213.6%	222.8%	206.9%	207.4%	196.0%	189%	209%
Northeast Utilities	154.2%	149.4%	127.0%	123.5%	94.5%	64.3%	90.7%	113.3%	136.4%	129.0%	99.4%	95.3%	105.5%	108.4%	0.0%	118%	82%
NSTAR	138.4%	153.9%	130.0%	129.6%	124.7%	146.4%	180.8%	165.8%	160.8%	161.3%	170.2%	174.6%	189.3%	202.2%	213.9%	149%	190%
Puget Energy, Inc.	149.2%	146.4%	111.7%	119.5%	130.0%	155.2%	169.7%	145.8%	143.4%	143.5%	125.9%	128.9%	137.5%	132.7%	129.0%	141%	131%
UIL Holdings	129.1%	140.2%	113.8%	110.4%	113.9%	111.2%	151.5%	143.8%	140.9%	139.4%	125.8%	112.7%	141.6%	122.6%	158.4%	129%	132%
Average	154%	156%	134%	136%	137%	140%	160%	148%	153%	160%	149%	146%	161%	160%	151%	**148%**	**153%**
Composite																**148%**	**153%**

Source: Calculations made from data contained in Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 11

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2005

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
Averages:		
1992-2001	14.7%	341%
2001-2005	12.2%	299%

Source: Standard & Poor's Analyst's Handbook, 2006 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group	2.7	0.97	B+	B+
Grant Gas & Electric Group	2.1	0.90	B++	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

Exhibit___(DCP-1)
Schedule 13

UNS ELECTRIC
TOTAL COST OF CAPITAL

ITEM	PERCENT		COST RATE			WEIGHTED COST	
Short-Term Debt	3.96%		6.36%			0.25%	
Long-Term Debt	47.21%		8.16%			3.85%	
Common Equity	48.83%	9.50%		10.50%	4.64%		5.13%
Total	100.00%				**8.74%**		**9.23%**
						8.99% Mid-point	

UNS ELECTRIC
PRE-TAX COVERAGE

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Short-Term Debt	3.96%	6.36%	0.25%	0.25%	
Long-Term Debt	47.21%	8.16%	3.85%	3.85%	
Common Equity	48.83%	10.00%	4.88%	8.23%	(1)
TOTAL CAPITAL	100.00%		8.99%	12.33%	

(1) Post-tax weighted cost divided by .59345 (composite tax factor)

Pre-tax coverage = 12.33%/(0.25%+3.85%)
3.00 X

Standard & Poor's Utility Benchmark Ratios:

	BBB	A
Pre-tax coverage (X) Business Position:		
3	1.8 - 2.8x	2.8-3.4x
Total Debt to Total Capital (%) Business Position		
3	55 - 65%	50 - 55%

Note that a business position of "3" is shown here since S&P places most transmission and distribution utilities in a range of "1" to "4".

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDEL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

ALEXANDER IBHADE IGWE

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

On December 15, 2006, UNS Electric, Inc. ("UNS" or "Company") filed an application with the Arizona Corporation Commission ("Commission") for a rate increase and for approval of financing. My testimony addresses UNS' request for financing approval in this proceeding. The Company's request for rate recovery for Black Mountain Generating Station ("BMGS") is addressed in Staff witness Mr. Smith's testimony.

UNS requests Commission authorization to incur up to $40 million in new debt financing and to receive up to $40 million of new equity infusion from its parent company, for an aggregate of up to $80 million. Also, the Company seeks flexibility to issue a mix of short-term, intermediate-term and long-term debt, depending on prevailing market conditions at the time of debt issuance. Further, UNS seeks authorization to refinance any short-term or intermediate-term debt, issued in this proceeding, to long-term debt, without further Commission approval. UNS states that the terms of its proposed debt financing are currently unknown, and would be contingent upon prevailing market conditions as well as investors' assessment of its credit worthiness. The Company indicates that the proceeds of its proposed financing will be expended solely for the purpose of acquiring a 90 MW peaking facility, BMGS, at an estimated cost of between $60 and $65 million. The Company states that BMGS will be acquired at cost from its subsidiary, UniSource Electric Development Company ("UEDC"), and placed in service sometime around June 2008.

Staff concludes that this proposal is in the public interest and recommends approval. Staff's analysis indicates that if the proposed financing is issued in a 50/50 debt/equity configuration, it may have no material impact on Staff's recommended capital structure of 48.83 percent equity and 51.17 percent debt. Further, Staff finds that because of lack of specificity as to the terms of the proposed debt financing, pertinent parameters for measuring the Company's ability to service the debt obligations, such as Debt Service Coverage Ratio and Times Interest Earned Ratio, cannot be determined at this time.

In summary, Staff recommends the following:

1. That the Commission authorize UNS to incur up to $40 million in new debt financing and to receive up to $40 million in new equity infusion, for the sole purpose of acquiring BMGS.

2. That the Commission authorize UNS to issue up to $40 million in debt financing, as recommended in (1) above, in long-term debt, and in short-term to intermediate-term debt.

3. That the Commission authorize UNS to refinance any short-term and intermediate-term debt, issued under this docket, to long-term debt, without further Commission authorization.

4. That the Commission authorize UNS to issue guarantees and grant liens on some or all of its assets, including BMGS, and any other properties acquired subsequent to this transaction, to secure its obligation under the proposed debt issuance and to secure other obligations at the time such liens are granted.

5. That the Commission authorize UNS to engage in any transactions and to execute or cause to be executed any documents so as to effectuate the authorizations requested with this application.

6. That UNS file a report with Docket Control demonstrating that it had a DSC and a TIER equal to or greater than 1.0, at the time of new debt issuance, within 60 days from the close of each transaction under this docket.

7. That UNS file a report with Docket Control, within 60 days from the close of each financing package, describing the transaction and demonstrating that the terms are consistent with those generally available to comparable entities.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Alexander Ibhade Igwe. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. What is your current employment position?

A. I am employed with the Utilities Division of the Arizona Corporation Commission ("Commission") as an Executive Consultant III.

Q. Briefly describe your responsibilities as an Executive Consultant.

A. In my capacity as an Executive Consultant III, I perform complex financial analysis and make recommendations to the Commission on rate base, revenue requirement and rate design; for water, wastewater, electric and gas rate proceedings. Also, I provide recommendations on financing, merger and acquisitions, sales of assets, issuance and extension of Certificate of Convenience and Necessity as well as other ancillary matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Accounting from the University of Benin, Nigeria and a Master of Information Systems Management degree from Keller Graduate School of Management of Devry University. I was a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. I have attended various training classes and courses regarding regulatory audits, rate-making, and other utility related matters. In addition, in my over eight years working for the Utilities Division, I have prepared Staff Reports and pre-filed testimonies and presented oral testimonies in several proceedings before the Commission.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. I am presenting Staff's analysis and recommendations regarding UNS Electric, Inc.'s ("UNS" or "Company") application for financing approval relating to its proposed acquisition of the Black Mountain Generating Station ("BMGS"). The Company's request for rate recovery for BMGS is addressed in Staff witness Mr. Smith's testimony.

THE TRANSACTION

Q. Please provide a brief description of UNS' financing application

A. UNS seeks Commission authorization to issue up to $40 million in new debt financing and to receive up to $40 million in additional equity contribution from its parent company, UniSource Energy Corporation, for a total of up to $80 million. UNS states that its request for authority to obtain up to $80 million in new financing will allow it some flexibility in determining the appropriate mix of debt and equity financing to be used for the acquisition of BMGS. Also, the Company indicates that the proposed debt financing could be comprised of short-term, intermediate-term and long-term debt, depending on the prevailing market conditions, at the time of debt issuance. Finally, the Company requests Commission authorization to refinance any short-term or intermediate-term debt, incurred in relation to this financing, with long-term debt, without further Commission approval.

Q. What is the purpose of the proposed financing arrangements?

A. UNS states that the proposed financing is requested solely for the purpose of funding the acquisition of BMGS, from its subsidiary, UniSource Electric Development Company ("UEDC"). The Company estimates that the 90 MW peaking facility could cost between $60 million and $65 million upon completion in May, 2008.

Q. Why does UNS seek authorization to receive additional equity infusion from its parent company?

A. UNS states that the proposed equity infusion will provide it with the requisite funding for the acquisition of BMGS. The Company explains that its requested equity contribution under this proposal will be in addition to any other equity infusion previously authorized by the Commission in prior proceedings. Also, UNS contends that the requested mix of debt and equity financing is necessary to maintain a balanced capital structure, upon conclusion of this transaction.

Q. What is the Company's justification for seeking a mix of debt financing?

A. The Company states that its request for authorization to issue a mix of short-term, intermediate-term and long-term debt financing, if necessary, will allow it needed flexibility to optimize prevailing market conditions at the time of debt issuance. For example, if the Company finds that it is cost-effective to borrow short-term or intermediate-term debt, until market conditions become conducive for issuance of long-term debt, this request will avail it the flexibility to obtain an appropriate mix of debt financing.

Q. Did the Company specify the terms of its proposed long-term debt financing?

A. No. UNS states that the terms of the proposed debt financing will be contingent upon the prevailing market conditions as well as investors' assessment of its credit worthiness, at the time of debt issuance. However, the Company indicates that the proposed long-term debt could vary in maturity from five to thirty years, at a fixed interest rate. Also, UNS anticipates that the debt term could require a lump-sum principal payment, or some form of principal amortization. Furthermore, the Company indicates that its proposed debt securities may be effectuated through a private placement or public issue. As to collaralization of the debt, UNS suggests that the debt financing could be unsecured or secured by BMGS assets or by a mortgage lien on all its properties, including future assets acquired subsequent to consummation of this transaction.

Q. What are the terms of UNS' proposed short-term and intermediate-term debt?

A. Again, the Company states that the terms will depend on the prospective investors' assessment of its credit worthiness and the prevailing market conditions at the time of debt issuance. UNS anticipates that the new short-term or intermediate-term debt will have maturities ranging from one month to five years, with variable or fixed interest rates. The Company projects that the principal amounts might be due in a single payment or through some form of amortization. If the proposed short-term or intermediate debt requires collateralization, the Company expects the security will be similar to those discussed above, in relation to its proposed long-term debt.

FINANCIAL ANALYSIS

Q. What is the impact of UNS' proposed financing on its capital structure?

A. The exact impact of UNS' proposed financing on its capital structure cannot be ascertained at this time. Although the Company specifically requests Commission authorization to issue up to $40 million of new debt financing, and to receive up to $40 million in new equity infusion, it also seeks some flexibility in determining an appropriate mix of debt and equity that would be issued when it engages in the transactions. Staff Consultant, David Parcell recommends a capital structure that is comprised of 48.83 percent equity, 47.21 percent long-term debt and 3.96 percent short-term debt (51.17 percent in aggregate debt). If the Company issues $40 million in new debt financing and receives $40 million in new equity infusion or engages in a different configuration of 50/50 debt/equity financing, the proposed financing will have no material impact on

Staff's recommended capital structure. The scenario described above will result in a capital structure that is consistent with the Company's expressed intent to maintain a balanced capital structure, subsequent to the conclusion of this transaction.

Q, Please comment on the Company's proposal to issue a mix of short-term, intermediate-term and long-term debt.

A. Staff agrees with UNS' assertion that it may be prudent to issue a mix of debt financing, consisting of short-term, intermediate-term and long-term debt, in order to optimize prevailing market conditions. Also, Staff accepts the Company's request for authorization to refinance any short-term and intermediate-term debt, issued in relation to this application, to long-term debt, without further Commission authorization. To request the Company to file for prior Commission authorization before refinancing any proposed short-term and intermediate-term debt, to long-term debt, could be burdensome and preclude the Company from taking advantage of fluid market conditions. However, Staff recommends that any future refinance of short-term and intermediate-term debt issued under this docket should be communicated to the Commission within 60 days of close of the transaction.

Q. Did Staff calculate any financial parameters in relation to UNS' request for authorization to issue debt?

A. Staff did not calculate the traditional parameters, such as Debt Service Coverage ("DSC") ratio or Times Interest Earned Ratio ("TIER"), for determining a utility's ability to service its debt obligations. Staff's ability to calculate DSC and TIER on UNS' proposed debt financing is hamstrung by the general nature of its application. For example, the Company's request indicates issuance of up to $40 million in new debt financing, which is neither specific as to the exact debt amount nor composition of the proposed debt. Also, the other factors such as interest rates and durations, are vague at this time.

Q. Please explain the terms DSC ratio and TIER.

A. A DSC represents the number of times internally generated cash flow covers debt service (principal and interest) on debt financing. A DSC greater than 1.0 indicates that operating cash flow is adequate to make interest and principal payments on long-term debt. A DSC less than 1.0 indicates that cash flow generated from operations may not be adequate to fulfill debt obligations, and that funds from other sources may be required to avoid default.

TIER represents the number of times operating income will cover interest expense on long-term debt. A TIER greater than 1.0 means that operating income is sufficient to make interest payment on debt.

Q. Does Staff recommend any DSC or TIER in this proceeding?

A. Yes. Although, the DSC and TIER relating to UNS' proposed debt financing cannot be determined at this time, for the reasons discussed above, Staff recommends that UNS demonstrate that it meets a minimum DSC and a TIER, equal to or greater than 1.0, at the time of each debt issuance.

RECOMMENDATION

Q. What is Staff's recommending regarding UNS proposed financing?

A. Staff recommends the following:

1. That the Commission approve UNS request to incur up to $40 million in new debt financing and to receive up to $40 million in new equity infusion, for the sole purpose of acquiring BMGS.
2. That the Commission authorize UNS to issue up to $40 million in debt financing, as recommended in (1) above, in long-term debt, and in short-term to intermediate-term debt.
3. That the Commission authorize UNS to refinance any short-term and intermediate-term debt, issued under this docket, to long-term debt, without further Commission authorization.
4. That the Commission authorize UNS to issue guarantees and grant liens on some or all of its assets, including BMGS, and any other properties acquire subsequent to this transaction, to secure its obligation under the proposed debt issuance and to secure other obligations at the time such liens are granted.
5. That the Commission authorize UNS to engage in any transactions and to execute or cause to be executed any documents so as to effectuate the authorizations requested with this application.
6. That UNS file a report with Docket Control demonstrating that it had a DSC and a TIER equal to or greater than 1.0, within 60 days from the close of each new debt financing under this docket.
7. That UNS file a report with Docket Control, within 60 days from the close of each financing package, describing the transaction and demonstrating that the terms are consistent with those generally available to comparable entities.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING	) DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

STEVE TAYLOR

ELECTRIC UTILITY ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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ENGINEERING REPORT ST-1

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE
DOCKET NO. E-01773A-04-0528

UNS Electric filed a rate application with the Arizona Corporation Commission ("ACC or Commission") on December 16, 2006. The twelve months ending June 30, 2006, was selected by UNS Electric as its test-year for all rate making revenues, rate based utility plant, and operating expenses. A Quality of Service Assessment was conducted to assure the need for facilities included in rate based utility plant. A Used and Useful Assessment was conducted on plant in service as of June 30, 2006. Construction Work in Progress ("CWIP") in effect as of June 2006 was also included in the rate based utility plant and was similarly reviewed. Additionally, UNS Electric requests inclusion of a post test year adjustment to rate base for a proposed generating station referred to as the Black Mountain Generating Station. This testimony concerns these proposed additions to rate based utility plant.

WITNESS BACKGROUND AND QUALIFICATIONS

Q. Please state your name, occupation, and business address.

A. My name is Steve Taylor. I am an Electric Utility Engineer employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I graduated from Duke University in 1970 with a Bachelor of Science degree in Electrical Engineering.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the States of Arizona and Maryland as a Professional Engineer - Electrical.

Q. Briefly describe your responsibilities as an Electric Utility Engineer.

A. I joined the Staff as an electric engineer in October, 2006. In my capacity as an Electric Utility Engineer, I have investigated the quality of service provided by two electric utilities in Arizona as part of financing applications before the Commission. I have prepared Commission Utility Staff positions on two line siting cases, the Arizona Public Service ("APS") Pinnacle Peak to TS 9 500/230 kV project and the Salt River Project ("SRP") Desert Basin 230 kV project. I have worked with area utilities in setting up load studies as part of the Commission's Biennial Transmission Assessment ("BTA"). I have worked with APS on preparing a Commission Utility Staff position on a high voltage transformer sharing agreement and sale of two properties.

Q. Please describe other pertinent work experience.

A. I have over 30 years of experience as an engineer and manager in the electric utility industry. I was employed by Potomac Electric in Washington, D.C. and Maryland from 1970 through 2002. During that time I: 1) analyzed and planned transmission and distribution system improvements; 2) managed the design and construction of various transmission and distribution assets 3) managed the operations and maintenance function involving various transmission and distribution assets. Additionally, I was employed by Power Engineers ("Power") in Hailey, Idaho from 2003 through 2006. During that time I was contracted to Texas Utilities in Ft. Worth, Texas to manage on site the various transmission line and substation construction plans generated by Power. This primarily involved the scheduling of construction activities, resolving of design and construction issues, bidding out contracts, resolving contractor payments and assisting remotely located Power staff with design issues on new projects.

Q. Have you previously testified before this Commission?

A. Yes. I have experience testifying before the Commission. I have provided testimony for two transmission line applications for a Certificate of Environmental Compatibility.

PURPOSE AND PREPARATION OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. I am providing Staff's testimony concerning the quality of service supplied by UNS Electric, a field assessment of used and useful assets, a field assessment of construction work in progress ("CWIP") assets and a brief overview of the proposed Black Mountain Generating Station ("BMGS") project.

Q. How have you prepared for your testimony?

A. I have reviewed information on file, issued data requests to UNS Electric and reviewed those responses, inspected UNS Electric plant facilities and talked with UNS Electric personnel.

Q. When did you inspect UNS Electric's facilities?

A. I inspected various facilities and consulted with UNS Electric personnel as described in Staff's Engineering Report relative to this docket (hereinafter referred to as the "Report") on May 30 through June 1, 2007, in the Tucson area and on June 6 through 9 in the Kingman area. Additionally, I was in Tucson on January 22, 2007, on a matter unrelated to the subject Docket and visited various facilities with UNS Electric personnel, two facilities of which pertain to the subject docket. My findings are in the Report and are attached as Exhibit ST-1.

Q. What UNS Electric personnel have you talked with concerning this docket?

A. I have talked primarily with Mr. Ed Beck, Mr. Sam Ruggell, and Mr. Ricky Robles representing UNS Electric in Santa Cruz County and Mr. Bill Degilio representing UNS Electric in Mohave County. I did have short discussions with several other UNS Electric representatives during the site visits in Santa Cruz County and Mohave County and some others while setting up the site visits and resolving data response questions.

Q. What documentation have you reviewed in preparing your testimony?

A. I have reviewed all rate application material filed by the applicant, numerous responses to Staff data requests and information made available for review during the May and June, 2007 site visits.

Q. Is your testimony herein based upon the aforementioned facility site observations, conclusions drawn from review of available documentation, information gathered by talking with applicant personnel and your educational background and work experience as a utility professional?

A. Yes it is.

QUALITY OF SERVICE ASSESSMENT

Q. How does Staff determine whether or not UNS Electric or any electric utility is providing reliable electric service?

A. Unfortunately, there are no single measures or even groups of measures that can definitively declare a utility is or is not supplying reliable electric service to its customers. The answer to this question has generally been to look at each utility individually, taking into account the unique conditions often found in different parts of the country, the unique conditions that a utility may have to deal with in its service territory, outage measurement systems the utility is using or may be in a position to use, and the utility's general approach and responsiveness to outages. The answer to the question of reliable electric service is based on a professional analysis of all the data available and a conclusion usually qualified with considerations for any unique circumstances that may be part of the utilities' operating circumstances.

Q. Would Staff agree that utilities should be striving for uninterrupted service?

A. Yes, moving toward uninterrupted service is a worthwhile goal for any utility, but the reality is that most utilities on a system wide basis will find this unattainable on a 100 per cent continuous basis. The high cost of constructing electric plant means that utilities must build and improve utility plant facilities with a goal of supplying reliable electric service at a reasonable cost. This reliable electric service at reasonable cost measure is somewhat subjective and interpreted differently by utilities and customers. An appropriate approach for utilities is to measure what they have with regard to outage histories and then strive for continuous improvement in those measures. The result should be that customers should be the recipient of continually improved electric service and the utility can appropriately and reasonably manage the cost of needed plant improvements.

Q. If there is no single measure of reliability and no precise goal, then what exactly does Staff look at to reach a conclusion on reliability of electric service?

A. Staff looks at all the information that is available and then reasonably weighs all the individual conclusions to reach an overall conclusion. There are numerous factors that should be looked at in a utility like UNS Electric. A complete analysis of each factor is included in the Report attached as Exhibit ST-1 and each factor is briefly described below.

Reliability indices for U. S. utilities are available on a limited basis and it is useful to compare where one stands as a utility with respect to these established metrics. UNS Electric showed some favorable comparisons to some of the available reliability metrics and some lower performance comparisons to others. Summer storm activity appeared to be a consideration in the lower performance comparisons.

A review of worst performing feeders was conducted to see how UNS Electric was responding to areas where customers were being most impacted by outages. UNS Electric personnel were cognizant of these problem areas and generally seemed to be taking proactive steps to minimize future problems.

A trend analysis was considered for review as a tool to determine if service is improving, degrading or remaining constant. Unfortunately, there was insufficient data prior to 2004 so this analysis was not performed. It will however, be a useful tool in future years to track changes in reliability metrics.

Quality of service complaints that were received by the Commission regarding UNS Electric service reliability were reviewed for the years 2004 through 2007. A total of 32 complaints were examined with most complaints of a general nature related to power outages and as described in the Report attached as Exhibit ST-1. No unusual patterns or issues were noted in the complaints on file with the Commission.

A review of the UNS Electric transmission system was conducted with primary reliance on the Biennial Transmission Assessment ("BTA"). There are several identified projects and activities noted in the BTA affecting UNS Electric; however, this information is well known to UNS Electric and various activities are underway to address these issues.

Load growth on the UNS Electric system was reviewed as the growth of an electric system can impact reliability. UNS Electric is looking at very high growth rates especially in some parts of the Mohave service territory which needs to be considered in conjunction with the capital construction program.

The five year capital construction program was reviewed and the expenditures planned seemed commensurate with a rapidly growing service territory. It should be noted that Staff is not implying any specific treatment or recommendation for rate base or rate making purposes in any UNS Electric rate filings.

Q. In consideration of all the factors then what is Staff's conclusion on UNS Electric supplying reliable electric service?

A. Staff believes UNS Electric is supplying its customers with reliable electric service.

Q. Are there any considerations that should be noted as part of Staff's conclusion that UNS Electric is supplying reliable electric service?

A. There is clearly room for improvement in reliability of any utility electric system. Staff suggests to UNS Electric that continued improvement of its outage measurement systems, and a focus on improving outage metrics especially with regard to those associated with the "Worst Performing Feeders", will serve its customers well and allow UNS Electric the most effective use of its capital budget associated with outage improvement.

USED AND USEFUL ASSESSMENT

Q. How did Staff decide which projects should be part of a Used and Useful Assessment?

A. The initial approach for this assessment was to look at a representative group of projects placed in service and considered Used and Useful during the rate case test year ending June 30, 2006. The data response by UNS Electric to this issue produced a listing too short to provide a representative sampling, so the period for review was increased to the 36 month period ending June 30, 2006. This produced a suitable listing of projects to choose from and ten projects were selected for review representing different cost classes (transmission, production, etc.) and equally divided between the Santa Cruz and Mohave service territories.

Q. What did Staff look for in making a Used and Useful determination?

A. The primary objective in this assessment was to determine that the asset reviewed had verifiable documentation available demonstrating that the asset was placed in service no later than the end of the test year and it was performing the function for which it was intended. Additionally, as part of a prudent and reasonable determination for each asset, available documentation was reviewed to determine the asset was warranted and the cost of the asset was reasonable and had appropriate management review.

Q. Could all this have been accomplished through reviewing responses to data request?

A. No, a field review is required to confirm the function of the asset is being accomplished, along with reviewing data responses. In addition, a general discussion of each asset was accomplished at UNS Electric offices just prior to the May and June, 2007 site visits to Tucson and Kingman.

Q. What were the results of Staff's review of the ten projects selected for the Assessment?

A. All projects were determined to be Used and Useful no later than June 30, 2006. A detailed summary of the findings on each project are in the Report and are attached as Exhibit ST-1.

Q. Are there any special considerations or findings in any of the project reviews in the Used and Useful Assessment?

A. Yes. One project, the Tubac Golf Resort Overhead to Underground conversion with a cost of $236,873.96, had the appearance of a project that might be significantly reimbursed by the customer and, if so, then not eligible for inclusion in rate base in the portion reimbursed. UNS Electric was unable to provide sufficient documentation at the time of this testimony to make a definitive determination on the reimbursable portion of this project and resultant rate base inclusion, if any. Staff recommends that a final determination be made on the treatment of this project after UNS Electric has supplied the necessary documentation.

Q. Were there any other findings of note?

A. Staff generally found all facilities inspected in the field to be up to National Electric Safety Code Standards and built in accordance with good utility practices. Staff did note two issues at London Bridge Substation in the Report with regard to security fencing and oil containment that warranted further review by UNS Electric.

CWIP ASSESSMENT

Q. How did Staff decide which projects should be part of a CWIP Assessment?

A. The approach for this assessment was to look at a representative group of projects that were carried as CWIP by UNS Electric and identified as Net CWIP June 2006. The five identified projects totaled approximately $4.1 million in CWIP as of June 2006, and were selected based on obtaining a representative sampling of cost classes (transmission, production, etc.) in both the Santa Cruz and Mohave service territories. Additionally, as the list of CWIP projects provided by UNS Electric was extensive, the selected projects were the higher accumulated cost projects to adequately represent the $10.8 million net CWIP of June 2006 included in the rate case application.

Q. What did Staff look for in making a CWIP determination?

A. Staff's primary objective in this assessment was to determine that the asset reviewed had verifiable documentation available that it was placed in service at a specific date after June 30, 2006 or it was continuing as a CWIP project. Additionally, as part of a prudent and reasonable determination for each asset, available documentation was reviewed to determine the asset was warranted and the cost of the asset was reasonable and had appropriate management review.

Q. Could all this have been accomplished through reviewing responses to data requests?

A. No, a field review is required, to confirm the function of the asset is being accomplished, or will be accomplished at some future time, along with reviewing data responses. In addition, a general discussion of each asset was accomplished at UNS Electric offices just prior to the May and June, 2007 site visits to Tucson and Kingman.

Q. What were the results of Staff's review of the five projects selected for the CWIP Assessment?

A. All projects were determined to be appropriately included in CWIP as of June, 2006. A detailed summary of the findings on each project is in the Report and is attached as Exhibit ST-1.

Q. Are there any special considerations or findings in any of the project reviews in the CWIP Assessment?

A. Yes. One project, the Rhodes Homes 21 kV supply with a CWIP inclusion of $442,254.92 was determined to be in service May 26, 2006 and therefore could reasonably qualify for Used and Useful treatment. It was noted in the review of this project with the UNS Electric representative that the cost of the project was advanced 100 per cent by the customer and the construction amount was then subject to repayment to the customer by UNS Electric when certain load conditions (described in an Agreement between parties) on the new supply line developed.

Q. Were there any other findings of note?

A. Yes, all facilities inspected in the field associated with the CWIP review were found to be up to National Electric Safety Code Standards and built in accordance with good utility practices.

BLACK MOUNTAIN GENERATING STATION ("BMGS") REVIEW

Q. Why is there a review of the BMGS in your Report?

A. BMGS is a proposed 90 megawatt facility in Mohave County for which $60 million to $65 million has been included in the rate base application for procurement by UNS Electric. UNS Electric has provided pre filed testimony with regard to BMGS. It was expedient for Staff to conduct a site review of this project while in the area June 6 and 7, 2007 in the course of the other field reviews described earlier in this testimony. The primary objective was to verify what stage of construction BMGS was in.

Q. What observations did Staff make about the BMGS?

A. Before the field review, Staff inquired about the expenditures to date for BMGS. Staff was advised that approximately $41 million has been spent to date for the two turbines, engineering, station materials and gas line construction. Staff reviewed the field site for the BMGS on June 6, 2007 with a UNS Electric representative and observed the land at issue is "open desert" south of Kingman and a few miles from the existing Griffith Power Plant. There is a large gas line (obviously for the proposed plant) being constructed along the frontage and through a portion of the property and a 69 kV wood pole line exists on the frontage road for the site. No other utility infrastructure (or structures of any kind) was observed on the site. A more complete summary of observation on the BMGS are in the Report and are attached as Exhibit ST-1.

Q. What conclusions did Staff make about the BMGS?

A. Staff concludes only that the BMGS site on June 6, 2007 near the Griffith Power Plant showed active construction of a gas line project and the site was readily accessible to an existing 69 kV line on the site's road frontage. No other construction activities, including equipment storage of any kind, were noted on the site.

SUMMARY OF TESTIMONY CONCLUSIONS

Q. Please summarize the conclusions of your testimony.

A. Staff has four separate conclusions. First, UNS Electric is supplying its customers with reliable electric service. Staff offered UNS Electric recommendations on outage measurement initiatives (improved outage measurement in Mohave County and a focus on identifying and improving performance of "Worst Performing Feeders" in both the Mohave and Santa Cruz territories). Second, all projects in the Used and Useful review were determined to be Used and Useful no later than the end of the test year which was June 30, 2006. One project, the Tubac Golf overhead to underground conversion, appeared to possibly have a significant customer contribution which needs to be resolved before inclusion of the project in rate base. Two field observations during the review are also noted at the London Bridge substation with regard to security fencing and oil containment for any appropriate UNS Electric action. Third, all projects in the CWIP review were determined to be appropriately classified as Net CWIP June 2006 although this is not a recommendation for or against inclusion of any CWIP in the rate base application. One CWIP project, the 21 kV supply to Rhodes Homes well pumps, actually qualified for Used and Useful treatment since the 21 kV line was determined used and useful on May 26, 2006 which was prior to the end of the test year. There is, however, a customer advance for this project that must be resolved in either a CWIP or Used and Useful treatment. Fourth, a review of the field conditions at the proposed BMGS project determined the site work for this project is in the initial stage with gas line construction in progress and an existing 69 kV line noted on the frontage road of the site. No other construction materials or activities were observed on the site.

Q. Does this conclude your direct testimony?

A. Yes, it does.

M E M O R A N D U M

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: June 15, 2007

RE: ENGINEERING REPORT ANALYZING QUALITY OF SERVICE MATTERS, USED AND USEFUL REVIEW AND CONSTRUCTION WORK IN PROGRESS REVIEW RELATED TO THE UNS ELECTRIC COMPANY RATE CASE APPLICATION, DOCKET NO. E-04204A-06-0783.

Attached is an engineering report documenting a Utilities Division quality of service assessment for the calendar years 2004 through 2006, and a Used and Useful Review and Construction Work in Progress ("CWIP") Review of UNS Electric for the three year period ending June 30, 2006. It is intended for use as a Commission Staff reference document in the pending UNS Electric rate case, Docket No. E-04204A-06-0783.

Engineering finds no reason to recommend consideration of quality of service mitigation measures as part of the pending UNS Electric rate case based upon the results of the assessment; however, we do offer suggestions on future reliability initiatives that would, Staff believes, well serve UNS Electric and its customers.

Engineering further finds no reason to exclude any of the ten projects in the Used and Useful Review from rate base inclusion with the possible exception of the Tubac Golf Resort Overhead to Underground conversion which may have a significant customer contribution component. UNS Electric was not able to provide sufficient documentation at the time of this report to make a definitive determination on this project. A few suggestions regarding substation particulars on other projects were included in the report for necessary follow up action by UNS Electric.

Engineering further finds all five projects in the CWIP review were in construction at the time of the CWIP accounting in June 2006 with three completed at the time of this Report and two projects continuing. One of the completed projects, the Rhodes Homes 21 kV supply for water pumps was in service just prior to the end of the test year and qualifies for Used and Useful treatment with consideration for a 100% customer advance. Engineering again notes, as in the Report, that the CWIP review is not a recommendation for or against including these projects associated CWIP cost in rate base.

Additionally, for general information, Engineering was in a position to make a cursory review of the proposed Black Mountain Generating Station project (scheduled for service in 2008) which was in the vicinity of various site visits in Mohave County. The Report includes a brief review of those findings.

SHT:tdp

Originator: Steve Taylor

Attachment: Original and Thirteen Copies

ENGINEERING REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

UNS ELECTRIC, INC.
RATE CASE
DOCKET NO. E-04204A-06-0783

STAFF'S ASSESSMENT OF:

QUALITY OF SERVICE

USED AND USEFUL CAPITAL ASSETS

CONSTRUCTION WORK IN PROGRESS CAPITAL ASSETS

BLACK MOUNTAIN GENERATING STATION

JUNE 28, 2007

STAFF ACKNOWLEDGMENT

This Engineering Report was prepared by the Arizona Corporation Commission Utilities Division ("Utilities Division") for use in the UNS Electric, Inc. ("UNS Electric") rate case, Docket No. E-04204A-06-0783. It provides an analysis of the quality of service provided by UNS Electric for calendar years 2004 through 2006. It also provides a used and useful assessment regarding capital improvements made in the thirty six months prior to June 30, 2006 (end of rate case test year). Additionally, it addresses construction work in progress ("CWIP") that has been included in rate base in the Application. Observations of the Black Mountain Generating Station and related discussion with UNS Electric are also included for general information. The report documents an engineering assessment by Steve Taylor of the Utilities Division regarding these three primary matters and the one observational issue.

Steve Taylor actively monitors quality of service matters for all Arizona utilities on an ongoing basis. His quality of service assessment of UNS Electric is based upon a review and analysis of the company's response to data requests concerning quality of service matters.

A Used and Useful assessment requires a physical survey of selected new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. Mr. Taylor has extensive industry experience regarding such investigations. His used and useful assessment of UNS Electric's capital improvements is based upon inspection of a sampling of UNS Electric facilities and review and analysis of the company's response to data requests concerning its capital improvements.

A Construction Work in Progress ("CWIP") assessment requires a review of newly completed (since the end of the test year) and on going capital projects that were included in the rate base of the Application and followed by a selected physical survey of the facilities. Mr. Taylor has extensive industry experience regarding such investigations. His CWIP assessment of UNS Electric's capital improvements is based upon inspection of a sampling of UNS Electric's facilities and review and analysis of the company's response to data requests concerning its capital improvements.

Steve Taylor

Steve Taylor
Electric Utility Staff

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Used and Useful Review Projects-May 7, 2007 .... **Exhibit 1**

Checklist for ACC Santa Cruz Project Review .... **Exhibit 2**

Checklist for ACC3 Mohave Project Review .... **Exhibit 3**

CWIP Review Projects-May 7, 2007 .... **Exhibit 4**

I. PURPOSE OF ENGINEERING REPORT

This engineering report serves a three fold purpose. It documents a quality of service assessment of UNS Electric performed by Utilities Division Engineering Staff ("Staff"). Secondly, it provides a Used and Useful assessment of UNS Electric's capital improvements for the thirty six months ending June 30, 2006 (end of the test year) performed by Staff. Thirdly, it provides a Construction Work in Progress ("CWIP") assessment of projects that were included with rate base in UNS Electric's Application also performed by Staff. As a peripheral matter, in the process of conducting office and site reviews, it was expedient to conduct a preliminary review of the proposed Black Mountain Generating Station and these observations are included in the report also. The report is filed with the Arizona Corporation Commission ("Commission") in support of the Commission's evidentiary record for the UNS Electric's rate case, Docket No. E-04204A-06-0783.

II. QUALITY OF SERVICE ASSESSMENT

A. FRAMEWORK

Staff's quality of service assessment of UNS Electric covers the calendar years 2004 through 2006. It is based upon information collected via data requests of UNS Electric and an associated review of that information in comparison to an Institute of Electrical and Electronic Engineers ("IEEE") reliability measurement survey performed in 1995 and a specific review of distribution feeders with the highest UNS Electric outage rates. Additionally, this assessment considers findings of consumer complaints regarding quality of service filed with the Commission's Consumer Services Section. A review of the transmission system in the Applicant's service area is also considered utilizing the 2006 Biennial Transmission Assessment ("BTA") which was performed in accordance with Arizona Revised Statute §40-360.02.G. Forward projections of expected future reliability are then offered in consideration of the aforementioned analyses plus growth rates and projected capital construction. The Assessment closes with Conclusions based on the available information.

B. DISTRIBUTION SYSTEM

Distribution reliability is a subjective measure and must generally take into account the available outage measurement systems, comparisons to other accepted industry indices, comparison to internal company indices for trend analysis, identification of problem areas and corrective action. This information is then considered along with other factors described in the subsequent items of the Quality of Service Assessment to reach an overall Quality of Service Conclusion (Item II.F).

B.1 RELIABILITY INDICES

The Commission has adopted a North American Reliability Council ("NERC") definition of reliability for Staff's use in the Biennial Transmission Assessment. Reliability is comprised of two components: adequacy and security. Adequacy is the ability of an electric system to supply the aggregate electrical demand and energy requirements of its customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. On the other hand, security is the ability of an electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. These components of reliability are subjective, not easily measured and leave much to interpretation.

Many utilities use numerical indices as a measure of an average customer's distribution service reliability. Such reliability indices are typically computed on an annual basis. A utility may then set reliability targets based upon benchmarked data from its own system. The IEEE has adopted a standard definition for several reliability indices for electric distribution systems and established a national benchmark database via a 1995 IEEE survey of the electric utility industry. The most commonly used reliability indices are System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), and Customer Average Interruption Duration Index ("CAIDI"). All three reliability indices are defined in IEEE Standard 13-2003, IEEE Guide for Electric Power Distribution Reliability Indices.

SAIFI is the average number of interruptions experienced by customers per year. SAIDI is the average number of interruption minutes experienced by customers per year. CAIDI is the average duration of interruptions. MAIFI is the average number of momentary interruptions experienced by customers per year where a momentary interruption is generally defined as 5 minutes or less and is associated with the normal function of electric system restorative devices such as circuit breakers and reclosures. The MAIFI statistic is a lesser used measure in the industry as it is not indicative of longer outages; however, it does measure an "annoyance factor" with customers when short interruptions (5 minutes or less) are excessive, thereby causing the frequent resetting of many electronic devices in the home or business. Per Rural Utilities Service ("RUS") Bulletin 161-5, the RUS considers a SAIDI of five hours (300 minutes) or more per consumer as unacceptable except under very unusual circumstances. The IEEE 1995 Survey established typical reliability index values for the electric utilities in the United States as displayed in the following table.

Table 1
Typical Reliability Index Values for US Utilities

Average	SAIFI	SAIDI	CAIDI	MAIFI
Top quartile	0.90	54	55	1.5
Second quartile	1.10	90	76	5.4
Average	1.26	117	88	6.6
Third quartile	1.45	138	108	11.1
Bottom quartile	3.90	423	197	13.7

Staff proposes to compare in Table 2 the actual UNS Electric distribution system reliability indices to the typical reliability indices contained in Table 1. The UNS Electric data utilized for this comparison is the year end metric for each of the last three years reliability indexes for UNS

Electric in each of the 4 categories noted in Table 1 and itemized by Santa Cruz County, Mohave County and UNS Electric's total territory. These measures are an aggregate of all measures made on a UNS Electric system wide basis in total for UNS Electric and in part for UNS Electric's Mohave and Santa Cruz Counties. Although there are obviously some variations in the measures in different parts of UNS Electric's 7,250 square mile Mohave service territory and 677 square mile Santa Cruz territory due to a variety of factors such as customer density, geography and weather patterns for example, the aggregate measures are a reasonable indicator of overall reliability.

Additionally, these UNS Electric measures in Table 2 include "Major Event Days" generally associated with major storms and scheduled outages generally associated with maintenance or construction work activities pre arranged to minimize customer impact. This is necessary because UNS Electric does not collect outage data with a differentiation between types of outages so their data is all inclusive. This puts UNS Electric at a disadvantage in the comparison to the IEEE 1995 data which normally would have been done both with and without "Major Event Days" and scheduled outages. This would be an appropriate accommodation in the UNS Electric comparison, in Staff's opinion, due to the nature of data collection in the 1995 IEEE Survey not being all inclusive in all cases. Nonetheless, this comparison of UNS Electric data to IEEE data can still be made with some explanation to address this anomaly. On this basis, Staff can make an objective assessment of the quality of service being provided to UNS Electric's distribution system customers.

The results of this comparison are summarized in Table 2 below with the UNS Electric individual year and service territory metrics positioned in the corresponding IEEE quartile from Table 1. The results show that UNS Electric's reliability indexes range from top quartile to bottom quartile performances in the four metrics.

Table 2

UNS Electric Reliability Index Values Compared to Typical for US Utilities

Ranking	SAIFI	SAIDI	CAIDI	MAIFI
Top quartile				SC '05 (0.7) SC '06 (1.2)
Second quartile	MO '04 (1.01) SC '04 (1.07) UN '04 (1.03) MO '05 (1.08)	MO '04 (76) SC '04 (68) UN '04 (75) MO '05 (89)	MO '04 (76) SC '04 (64) UN '04 (73)	MO '05 (4.5) UN '05 (3.7) MO '06 (5.0) UN '06 (4.2)
Third quartile			MO '05(82) SC '05 (106) UN '05 (93) MO '06 (97) SC '06 (87) UN '06 (96)	
Bottom quartile	SC '05 (3.14) UN '05 (1.52) MO '06 (2.83) SC '06 (1.76) UN '06 (2.58)	SC '05 (334) UN '05 (142) MO '06 (275) SC '06 (153) UN '06 (245)		

Note: Designations are SC for Santa Cruz County, MO for Mohave County and UN for the combined Santa Cruz and Mohave counties each followed by their corresponding metric.

Under normal circumstance in which utilities would have removed most of their severe storm and scheduled outage impact from their metrics (for which UNS Electric is presently not programmed to do), Staff would expect to see generally second quartile performance for most of the metrics with some first quartile performance. In this analysis for UNS Electric, approximately half the metrics meet this expectation. The bottom quartile metrics are of some concern and must be looked at in conjunction with explanations of the data and the overall conclusions for the Quality of Service Assessment in Section II.F of this Staff Report.

UNS Electric has noted in their data submittals that there were 9 months in Mohave County and 3 months in Santa Cruz County over the 3 year analysis period in which customer outage minutes exceeded 1,000,000 minutes due primarily to summer monsoon activity. It is reasonable to conclude that a significant contributing factor to the bottom quartile performance is the impact of severe summer weather on UNS Electric's electric system with rural exposure. Additionally, it is noteworthy that the CAIDI metrics (SAIDI divided by SAIFI) fall into the higher third quartile and as this is a truer measure, in Staff's opinion, of how long someone affected by an outage will be out, it is a measure of significance. Also the MAIFI metrics are consistently good showing first and second quartile performance, although some of this may be attributable to UNS Electric's shorter measurement of a momentary outage (3 minutes versus the IEEE standard of 5 minutes).

B.2 WORST PERFORMING FEEDERS

Reliability indices on a system aggregate basis are useful for determining overall reliability; however, an aggregate review may tend to mask more severe problems in a particular area. For this reason Staff reviewed the history of the worst performing distribution feeders in each of the Mohave and Santa Cruz territories to determine if there were any particular service issues that required further attention. By definition, there will always be distribution feeders in the worst performing category since the measure is relative to all other distribution feeders of that utility in the study area regardless of their performance level. The intent of the review is to look at the impact to customers in any single year, the repeat impact if any feeder remains a worst performing feeder in different years, and the corrective measures employed by the utility.

Staff reviewed the data submitted by UNS Electric for the three worst performing feeders in Mohave County and makes the following observations:

1. Three years data was submitted (2004 through 2006) and no single feeder appeared in more than a single year.

2. The Golden Valley area appeared in both 2004 and 2005 but on separate feeders. No other particular geographic pattern was observed in the outages.

3. No action (other than restoration) was taken on most feeders over the three year period although underground cable was replaced and temporary facilities removed in two cases.

4. Using a modified definition of CAIDI (total customer minutes divided by customers affected) to determine average customer outage times, the performance ranges from 62 minutes per customer per year to 333 minutes per customer per year. The 62 minutes per customer per year equates to second quartile performance relative to the IEEE standard and the 333 would equate to fourth quartile. Comparison of individual feeder metrics to the IEEE standard in this manner is not standard protocol however it does indicate where more review might be appropriate. The 62 minutes per customer per year is reasonable performance and the 333 minutes per customer per year and measures of this magnitude require consideration with other factors.

5. Of the nine feeders reviewed over three years, five had outage times averaging less than 100 minutes per customer per year and four had outage times averaging more than 100 minutes per customer per year. An outage rate of 100 minutes per customer per year equates to third quartile CAIDI performance in the normal definition of IEEE performance and would generally be considered an acceptable level of performance.

6. Outage performance was not correlated to any particular storm activity; however, Staff believes storms were a significant factor in these outages based on data supplied by UNS Electric and addressed in the final paragraph of Section II.B.1 herein.

Staff similarly reviewed the data submitted by UNS Electric for the three worst performing feeders in Santa Cruz County and makes the following observations:

1. Two years data was submitted (2005 and 2006). One feeder (C-8203 serving N. Pendleton) appeared in both years.

2. No action (other than restoration) was taken on all feeders over the two year period.

3. Using a modified definition of CAIDI (total customer minutes divided by customers affected) to determine average customer outage times, the performance ranges from 35 minutes per customer per year to 141 minutes per customer per year. The 35 minutes per customer per year equates to first quartile performance relative to the IEEE standard and the 141 would equate to fourth quartile. Comparison of individual feeder metrics to the IEEE standard in this manner is not standard protocol however it does indicate where more review might be appropriate. The 35 minutes per customer per year is reasonable performance and the 141 minutes per customer per year and measures of this magnitude require consideration with other factors.

4. Of the five feeders reviewed over two years, two had outage times averaging less than 100 minutes per customer per year and two had outage times averaging more than 100 minutes per customer per year and one had an outage time close to 100 minutes per customer per year. An outage rate of 100 minutes per customer per year equates to third quartile CAIDI performance in the normal definition of IEEE performance and would generally be considered an acceptable level of performance.

5. Outage performance was not correlated to any particular storm activity; however, Staff believes storms were a significant factor in these outages based on data supplied by UNS Electric and addressed in the final paragraph of Section II.B.1 herein.

In addition to the data review, Staff determined that four feeders selected from the worst performing list warranted a closer field review to evaluate field conditions and planned or otherwise possible improvements. The four feeders were selected based on those with greater customer impact and also characterization as a worst performing feeder in more than a single year. The feeders selected were inspected with Staff and UNS Electric personnel on May 31, 2007 in Santa Cruz County and on June 7, 2007 in Mohave County. A summary of the findings is provided as follows:

1. Canez Feeder C-8203 serving N. Pendleton Dr (Santa Cruz County) is a very long (approximately 100 miles) 13 kV distribution feeder serving residential and light commercial load in a partially mountainous area between Tucson and Nogales and east of

Interstate 19. Staff inspected portions of the feeder on May 31, 2007 with UNS Electric personnel and observed that problems were being regularly addressed with the addition of lightening arresters in selected locations, replacement of wood poles with steel poles in unstable soil areas along the Santa Cruz river, cross arm installation at selected locations to increase phase spacing, and fairly aggressive and recent tree trimming in the high vegetation areas close to the Santa Cruz river. Additional action being considered includes transferring some parts of this feeder to other feeders to reduce the length of line exposed and adding field reclosures (one presently exists) to isolate areas that have faulted in lieu of larger segments of the feeder. Since the area has topography which tends to make it subject to summer thunderstorms with resultant lightening and wind impacts and the overhead line exposure is high (about 50 percent of the 100 mile line is overhead), the feeder will likely remain as one which will require continued attention in the future. Staff was concerned that voltage degradation might be a problem at some locations on this feeder due to its long length; however, UNS Electric advised that maintaining the proper voltage has not been a problem. Staff believes UNS Electric has taken the appropriate steps to minimize customer outages as evidenced by the work of the last few years and is prepared to continue improvements of this feeder.

2. Mohave Feeder 8008 serving Aqua Fria and Golden Valley (Mohave County) is a short (less than five miles) 13 kV overhead distribution feeder serving residential load in a generally flat valley area between Kingman and Bullhead City. The topography of the area makes the feeder subject to lightening impacts during summer thunderstorms. The wind impact from these summer storms appears minor as there is minimal tall vegetation in the area that could be blown into the feeder although blowing debris presents some risk. The conductor is a relatively small Number 2 aluminum conductor steel reinforced ("ACSR") which is targeted for replacement with larger conductor probably in 2008 or 2009. A substantial portion of the feeder is built underneath a 69 kV feeder on a common pole line thereby protecting the under built 13 kV from lightening strikes and resultant outages. The rebuilding of the Number 2 ACSR line (comprising the bulk of the feeder) will provide additional lightening protection for the feeder due to the new construction standard requiring approximately 5 lightening arresters per pole mile of line thereby reducing the likelihood of any lightening induced outages on the 13 kV portion of the feeder. Staff believes this feeder as in place today presents a low risk of excessive outages affecting customers. Additionally, UNS Electric will be taking appropriate steps to further minimize customer outages on this feeder with the replacement of the feeder with larger conductor and associated lightening protection.

3. Mohave Feeder 8016 serving Aqua Fria and Golden Valley (Mohave County) is a relatively short (less than ten miles) 21 kV overhead distribution feeder with some underground serving residential load and some light commercial load in a generally flat valley area between Kingman and Bullhead City. The topography of the area is common to Mohave Feeder 8008 described above and makes the feeder subject to lightening impacts during summer thunderstorms. The wind impact from these summer storms appears minor as there is minimal tall vegetation in the area that could be blown into the

feeder although blowing debris presents some risk. A substantial portion of the feeder was rebuilt approximately six years ago however the standard at that time did not call for lightening arrester protection along the main feeder trunk except at transformers and other similar equipment connections. Staff believes this feeder as in place today presents a low risk of excessive outages affecting customers although outages could likely be most attributable to summer storm and lightening activity. Staff suggests that further monitoring of the outage performance of this feeder be conducted and if a correlation is made between excessive outage rates and area lightening activity, then consideration be given to the installation of additional lightening arresters along the feeder.

4. Mohave Feeder 6026 serving a portion of the Lake Havasu area out of North Havasu Substation is a moderate length (approximately 20 miles) 13 kV overhead distribution feeder serving residential load and some light commercial load in a hilly area just east of Lake Havasu. (Mohave County). The feeder is frequently constructed along the rear lot line of homes (instead of the more common street frontage construction) which may impede utility access and thereby increase some restoration times. The line construction employs lightening arresters at transformers and other similar equipment connections. The topography of the area makes the feeder subject to lightening impacts during summer thunderstorms. The wind impact from these summer storms appears minor as there is minimal tall vegetation in the area that could be blown into the feeder although blowing debris presents some risk. Staff believes this feeder as in place today presents a low risk of excessive outages affecting customers although outages could likely be most attributable to summer storm and lightening activity. Staff suggests that further monitoring of the outage performance of this feeder be conducted and if a correlation is made between excessive outage rates and area lightening activity, then consideration be given to the installation of additional lightening arresters along the feeder.

Staff finds no particular patterns or circumstances of concern in the outage statistics for UNS Electric's worst performing feeders based on the information available. Ordinarily, Staff would prefer to analyze a minimum of five recent consecutive years' data to identify repeating worst performing feeders and areas repeatedly affected. UNS Electric does not have any IEEE type data prior to 2004 since the Arizona assets of Citizens were not acquired until that time. The one feeder in the data supplied that does have more than one year in the worst performance category is C-8203 in Santa Cruz County however the corresponding modified CAIDI measurement is not unreasonable (141 in 2005 and 125 in 2006) and the number of affected customers is relatively low (approximately 200).

Staff did note that UNS Electric utilizes their Outage Management System ("OMS") to collect outage statistics in Santa Cruz County. The Santa Cruz system is capable, in Staff's opinion, of collecting and reporting data in a variety of ways with varying amounts of manual interaction. Staff believes it would benefit UNS Electric and their customers to begin collecting data annually in Santa Cruz County to determine the worst performing feeders (a minimum of three identified per year) for Santa Cruz County using a minutes (or hours) per customer affected per year measure (similar to UNS Electric's May 4, 2007 data response number six). This data collection could, Staff suggests, be modeled using reasonable assumptions to minimize any additional manual effort and still meet the goal of identifying feeders with the most adverse impact on customers. This type of review, in Staff's opinion, would allow UNS Electric to readily determine which feeders are most adversely impacting customer service and then allow UNS Electric Santa Cruz County to better focus their efforts on appropriate upgrades to those feeders.

Staff further notes that UNS Electric utilizes a manual system to collect outage statistics in Mohave County. UNS Electric Mohave County has a Work Management System and a partially developed Geographic Information System with future plans to employ an Outage Management Module as part of the Work Management System in the next few years. Although UNS Electric Mohave County does not have the present ability to collect outage data in the same manner as UNS Electric Santa Cruz County, Staff believes it would be beneficial to customers for UNS Electric Mohave County to similarly adopt a worst performing feeder review as described above for Santa Cruz County when sufficient tools are available to reasonably collect and analyze outage data.

B.3 TREND ANALYSIS

One useful tool for determining reliability is a comparative review of present reliability metrics in relation to past years metrics to determine if the overall reliability is improving, degrading or remaining constant. From that review, it is reasonable to project future reliability with consideration for other growth and capital investment plans.

Staff ordinarily expects to perform this type of analysis if data is available to do so, however, in this case, the data is not available. UNS Electric does not have any IEEE type data prior to 2004 since the Arizona assets of Citizens were not acquired until that time. Additionally, UNS Electric does not separately measure Major Event Days, so their data in the indices is all inclusive. A comparison using only the three years of available data is not constructive in this case. There is no way of differentiating severe storm occurrences from more routine outages and the trend analysis with and without Major Event Days cannot be performed. Additionally, three years data is only marginally sufficient to perform a meaningful trend analysis presuming all other data considerations are met.

C. QUALITY OF SERVICE COMPLAINTS

The Commission regularly receives telephone calls from utility customers who wish to voice their concern (or approval) on a variety of utility issues. These calls are logged in and referrals made to the appropriate utility for response to the customer on the particular issue cited by the customer. The Service Interruption category is one of the categories used to define the type of call received. Although the lack of or low instance of complaints in itself is not a definitive measure of acceptable reliability, a review of complaints when conducted in conjunction with other analyses (such as those included in this assessment) can weigh in the overall assessment conclusion.

Staff has reviewed the logged calls received by the Commission with regard to UNS Electric for the years 2004 through 2007 to date and with the Service Interruption identifier. The calls are summarized as follows:

1. Calendar Year 2004—No complaints received.

2. Calendar Year 2005—A total of 9 complaints received approximately evenly divided between Mohave and Santa Cruz Counties. Complaints were of a general nature (inability to contact UNS Electric promptly, longer outage or more frequent outages than expected, property damage, UNS Electric's response regarding restoration time inadequate). Complaints were received throughout the year with no particular geographic pattern observed. All complaints were addressed by UNS Electric and considered closed by the ACC.

3. Calendar Year 2006—A total of 22 complaints received approximately evenly divided between Mohave and Santa Cruz Counties. Complaints were of a general nature (inability to contact UNS Electric promptly, longer outage than expected, property damage, inability to determine time to make repairs). Complaints were received throughout the year with no particular geographic pattern observed. All complaints addressed by UNS Electric and considered closed by the ACC.

4. Calendar Year 2007—Staff notes only one complaint received at the time of this report with characteristics similar to complaints previously noted.

Staff finds no particular patterns or circumstances of concern in the complaints received by the ACC for the years 2004 through 2007 to date.

D. Transmission

The Commission performs a biennial transmission system assessment in accordance with Arizona Revised Statute §40-360.02.G. The latest assessment, the 2006 Biennial Transmission Assessment ("BTA") was approved by the Commission in March 2007 and evaluates the condition of the overall Arizona transmission system and addresses concerns or accomplishments in specific areas. The Assessment concludes that "In general, the existing and proposed Arizona transmission system meets the load serving requirements of the state in a reliable manner". Staff believes this overall Arizona conclusion is an important element of service reliability for all Arizona utilities; however it is appropriate to also consider any particular findings germane to UNS Electric in the BTA and additionally any other issues beyond the BTA that may be a consideration in assessing the UNS Electric transmission system.

Staff notes in the BTA that Reliability Must Run ("RMR") conditions in the Mohave and Santa Cruz areas supplied by UNS Electric require further analysis and possible action to maintain reliability. When an area must run its own generation due to transmission import constraints, the area is determined to be an RMR area. This is not necessarily undesirable as the cost of running area generation may be less than the cost of building new transmission. Nonetheless, utilities serving both the Mohave and Santa Cruz areas need to further review this matter so that a long term solution, if necessary, can be implemented. This conclusion is not unlike similar conclusions in year's past and resultant ACC directives to utilities in other areas such as Phoenix where RMR conditions were identified in the 2004 BTA and addressed through system planning analysis and resultant construction plans. The 2006 BTA process has identified this problem in the UNS Electric service territories (as it has done in other Arizona areas in earlier BTAs) and consequently the ACC has directed UNS Electric to perform the necessary RMR studies in conjunction with other associated parties as part of the upcoming 2008 BTA process.

Staff also notes from the BTA that the UNS Electric's plan to improve reliability for the Santa Cruz territory is to construct a second transmission line in the Nogales area from the proposed Gateway substation to the existing Valencia Substation to introduce redundancy of supply and thereby improve reliability. Additionally there are long term improvements for the Santa Cruz transmission system noted in UNS Electric's Ten Year Plan, particularly a new 138 kV circuit between Valencia Substation and Sonoita Substation and upgrade of the Valencia to Vail line from 115 kV to 138 kV.

From a power production and transmission perspective, it is important to consider that UNS Electric is largely dependent on others through contract to provide power and transmit that power to certain locations where it is then picked up on the UNS Electric transmission system. UNS Electric presently meets its power requirements through a Power Supply Agreement with Pinnacle West. Western Area Power Authority is utilized at many of the supply points to transmit power to a location where UNS Electric can tie in their transmission system. This approach to supplying and transmitting power is dependent on the protection and assurances contained in the associated contract conditions. Staff does not foresee any inherent reliability problems in this approach.

E. FORWARD PROJECTIONS

A Quality of Service Assessment is made at a particular point in time, the end of 2006 in this case. Generally however, it is appropriate to make a forward projection on Quality of Service to determine, based on available information, if the future trend is improving, deteriorating or remaining constant. This can be reasonably accomplished through a historical and future trend determination review of reliability considerations (preceding Items II.B, II.C and II.D) coupled with an analysis of projected customer load growth and projected capital investment noted in the following discussion.

E.1 PROJECTED LOAD GROWTH

UNS Electric is projecting overall (Mohave and Santa Cruz counties) customer base growth at an annual average rate of 6.6% for the year end 2006 through year end 2011 time period. They have experienced an actual 5.2% customer base growth rate for the year end 2003 through year end 2006 time period and this overall growth rate is greater in Mohave County at 7.0% than in Santa Cruz at 3.5% for the same period.

The customer base is higher in Mohave County (73,581 total number of customers all classes year end 2006) than Santa Cruz County (20,126 total number of customers all classes year end 2006). The residential class of customers dominates in number in both Mohave and Santa Cruz counties however the growth rate of residential customers is greater in Mohave County (7.6 % growth rate for 2004 through 2011) than in Santa Cruz County (5.0 % growth rate for 2004 through 2011).

The MWH sales figures generally follow the customer trends cited above.

The Mohave projected customer and load growth rates are within Staff's expectations in consideration of anticipated residential and commercial construction primarily in the Kingman and Havasu areas. This high growth is due to an influx of retirees from California, an influx of Nevada residents facilitated by the soon to be completed Hoover Dam Bypass as well as the historical load growth of the area.

The Santa Cruz projected customer and load growth rates are also within Staff's expectations in consideration of historical trends and the general lower growth rates projected as compared to Mohave.

In summary for growth, UNS Electric has experienced high customer and load growth and will likely continue to experience high growth rates. The growth is more pronounced in Mohave County.

E.2 PROJECTED CAPITAL INVESTMENT

UNS Electric will require future electric system capital investment in all major capital cost classes (new business, distribution system reinforcement, transmission and production) to provide service to new customers and ensure that overall reliability is adequate. The new business class includes all distribution lines and meters to supply new customers. The distribution system reinforcement class includes all new and upgraded distribution lines and substations. The transmission system class includes all new and upgraded transmission lines and substations (rated 69 kV and higher). The production class includes upgrades to power plant facilities.

UNS Electric has provided project specific information and cost for their capital budget plans for the years 2007 through 2011 as requested and itemized by the subject cost classes and further by Mohave and Santa Cruz counties. The requested information provided to Staff was submitted under a "Protective Agreement" requiring continued confidentially of the information. Staff therefore addresses UNS Electric's capital program in general terms.

Staff has analyzed the projected expenditures and projects for the years 2007 through 2011 in each service territory, Mohave County and Santa Cruz County and further itemized by cost classes previously noted. Staff believes the projected capital expenditures are appropriate in consideration of the projected growth rates noted in Item II.E.1, the reliability issues noted in Items II.B and II.C and the transmission issues noted in Item II.D. This does not however, imply a specific treatment or recommendation for rate base or rate making purposes in any UNS Electric's rate filings.

F. CONCLUSIONS FOR QUALITY OF SERVICE

Based on the review of UNS Electric's customer reliability measures, transmission system review, anticipated growth and future Construction Work Plans, it is Staff's conclusion that:

1. UNS Electric is supplying its customers in both the Mohave and Santa Cruz service territories with reliable electric service. The Distribution Reliability indices are heavily influenced by major storms and the rural nature of parts of the service territories.

2. The UNS Electric transmission system is adequately supplying both service territories; however there are several identified issues in the 2006 BTA that require resolution and UNS Electric is addressing these issues.

3. The load and customer growth rates of UNS Electric are reasonably projected based on past load and customer growth rates and overall population growth expected for Arizona. Both service territories are experiencing high growth rates with Mohave County experiencing a higher rate than Santa Cruz.

4. UNS Electric projects investment in its capital plant over the next five years in a manner that indicates new customers will be adequately and timely served and all customers can expect a reasonable level of reliability. UNS Electric's Five Year Construction Work Plan is appropriate in consideration of the expected growth and system reinforcement needs. This conclusion, however, does not imply a specific treatment or recommendation for rate base or rate making purposes in any UNS Electric's rate filings.

5. UNS Electric has an effective outage measurement system in Santa Cruz County with the ability to produce a variety of metrics. Staff believes UNS Electric would increase the value of this system to its customers and further improve reliability by additionally employing a metric to identify the worst performing feeders on a minutes (or hours) per customer affected per year measure in Santa Cruz County. The metric would then be used to take appropriate action on the worst performing feeders each year.

6. UNS Electric is moving toward an effective outage measurement system in Mohave County which should be similarly capable of producing a variety of metrics. Staff believes UNS Electric in Mohave County should adopt similar approaches to outage

measurement and corrective action as Santa Cruz County when the Mohave County tools to do so become available.

III. USED AND USEFUL ASSESSMENT

A. FRAMEWORK

A used and useful determination requires a physical survey of new and improved facilities to assure completion of construction, validation that equipment is fully operational, and that the facilities meet National Electric Safety Code ("NESC") requirements per Arizona Administrative Code R14-2-208. The investigator's level of industry experience is also critical in assembling criteria by which a valid sample of facilities is selected for field observation.

During electric facility site visits Staff generally ascertains: 1) facility security, 2) that proper safety and fire protection measures are employed, 3) all equipment have been constructed in compliance with NESC requirements, and 4) the operational status of facility. The site must be secure with proper height enclosures topped with either barbed wire or razor ribbon, and gate(s) and control house(s) are locked. Proper signage must be prominently displayed to inform the public that the facility poses an electric safety hazard. Each site is observed to ascertain that it is a safe working environment. Employee adherence to safe operating practices is also observed in the field. Particular attention is given to fire extinction capability, proper separation of equipment or use of fire wall barriers, and existence of oil cache basins for transformers.

Confirmation that equipment exists in the field and is operational is a prerequisite for a used and useful determination. Therefore the operational readiness status of all onsite equipment is noted. Presence of a properly maintained substation DC battery supply is verified. Equipment maintenance needs are also observed and maintenance practices confirmed. Storage of damaged or non-useable equipment onsite is discouraged. However, onsite storage of equipment for future construction projects or staging of maintenance and repair activities at remote sites is an acceptable practice. Storage of a mobile or spare transformer at a remote substation is an example of this practice.

B. PROJECT SELECTION

This used and useful determination of UNS Electric's capital improvements for the 36 month period prior to the end of the test year (June 30, 2006) is based upon inspection of a sampling of UNS Electric's facilities and review and analysis of the company's response to data requests concerning its capital improvements. Choosing an appropriate sample of facilities to inspect is a fundamental requirement in performing any valid used and useful determination. Normally, Staff would prefer to limit the project review to projects placed in service during the test year (ending June 30, 2006) however UNS Electric's data request response to this question produced a listing too short to allow a representative selection of projects. Subsequently, UNS Electric provided a listing of projects placed in service in the 36 month period ending June 30, 2006 which allowed for a representative selection of projects in both the Mohave and Santa Cruz counties.

It was determined that a site visit of UNS Electric's facilities and an office visit to review the Information Technology systems and other records was needed for the used and useful determination. However, UNS Electric has a large inventory of existing, new and upgraded facilities located state-wide. This made selection of a sample of facilities for field observation a necessity. Therefore, Staff organized its field visits by UNS Electric's major service territories in Mohave and Santa Cruz counties and selected a reflective sample of generation, transmission and distribution facilities in each jurisdiction.

Staff reviewed the listing of projects provided by UNS Electric and selected representative projects for further review. Five projects were selected for Santa Cruz County and five for Mohave County with a mix of Distribution, Transmission, Production and General Plant categories. The projects for both Santa Cruz County and Mohave County are listed in the attached Exhibit 1. Consideration for review was given to some projects that appeared to have a customer contribution element to see also how customer reimbursement was addressed in the rate base. Staff was also interested in the process used by UNS Electric to determine the need and costs for projects and the associated approval process. Also, confirmation through an independent and directly linked document was reviewed for each project to determine the plant was used and useful by the end of the test year (June 30, 2006) with those projects placed in service near the end of the test year receiving a higher degree of scrutiny. Finally, a field review of each project was conducted (or office demonstration in the case of the Information Technology project) to confirm the project was constructed and fairly represented in the information presented.

C. SITE VISITS AND FIELD OBSERVATIONS

Staff prepared a checklist of issues to review and resolve with each project and these checklists are provided herein as Exhibit 2 for Santa Cruz County and Exhibit 3 for Mohave County. A brief summary of the results from each project review is provided below:

<u>Santa Cruz County</u>

1. The Outage Management System ("OMS") Integration Project (rate base inclusion of $142,944.30) was satisfactorily demonstrated to Staff on May 30, 2007 at the Tucson Control Center verifying its usefulness as a tool to track outages and determine likely sources of trouble to expedite field dispatching and service restoration. This is a commonly used technology by utilities with widespread implementation in the utility industry beginning about ten years ago. UNS Electric's OMS application is similar to the OMS applications generally found with other similarly sized utilities. The project was verified as used and useful no later than January 27, 2005. The application is presently used exclusively used in Santa Cruz County.

2. The Valencia 20 Megawatt Turbine (rate base inclusion of $12,169,026.94), located at the Valencia Substation in Nogales, was the subject of a January 22, 2007 field inspection with Staff and UNS Electric representatives and a subsequent inspection on May 30, 2007. Staff reviewed the functionality of the turbine primarily in the January inspection and reviewed other aspects of the used and useful review (and construction work in progress discussed later) at the May review. Staff determined that the used and useful date for the project was June 21, 2006 based on Energy Management System operating logs indicating that the unit was operable from UNS Electric's control center and available to supply load when required. Additional attestations of the turbines readiness on June 30, 2006 were also observed. (Note that June 30, 2006 was the end of the test year and the closeness of these dates to the end of the test year required a close review of the documentation verifying the used and useful date.) The function of the turbine is to supply load when certain system conditions occur (primarily associated with unscheduled outages) and this readiness to supply load is the appropriate used and useful test for this asset. Further review of documentation confirmed that a thorough review of the Valencia turbine alternatives was considered and the Valencia turbine project was authorized and constructed in an appropriate manner. Staff reviewed the security measures associated with this facility, which is part of a larger substation and operations center, and found all standard precautionary measures were in place and fully functional.

3. The 46 kV Canoa to Kantor line (rate base inclusion of $2,282,720.61) was the subject of a January 22, 2007 field inspection with Staff and UNS Electric representatives and a subsequent inspection on May 30, 2007. Staff reviewed the functionality of the line primarily in the January inspection and reviewed other aspects of the used and useful review at the May review. Staff determined that the used and useful date for the project was August 30, 2004 based on Energy Management System operating logs. This line functions as a backup supply when certain system conditions occur (primarily associated with unscheduled outages) and numerous incidents of use were noted in 2005 and 2006 with an average of approximately ten uses each year to supply the Kantor substation under certain outage scenarios. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner.

4. The Kantor 7203 Overhead to Underground Nogales project (rate base inclusion of $333,333.86) was initially field reviewed by Staff and UNS Electric representatives on May 30, 2007. The project involved the replacement of approximately 2.5 miles of overhead 13 kV distribution line with underground cable starting about 0.5 mile from the Kantor Substation and proceeding toward the Whipple Observatory on Mount Hopkins. An original underground installation in the early 1970's served this load; however, an electrical fault incident in early 2000 caused the failure of this portion of the underground feeder and a temporary overhead line was installed to maintain service. State land

permit restrictions required the line to be underground and this was accomplished in 2005/2006 with the construction of the subject project. The in service date for this latest underground installation was determined to be in early 2006 although the requested more positive verification of the in service date was not available and has not been produced at the time of this report. Staff expects this documentation, when provided, will verify the project was in service prior to the end of the test year. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner.

5. The Tubac Golf Resort Overhead to Underground conversion (rate base inclusion of $236,873.96) was initially field reviewed by Staff and UNS Electric representatives on May 30, 2007. The project involved the removal of approximately one mile of 13 kV overhead distribution wire and poles and the installation of a similar length of 13 kV underground distribution cable with four above ground enclosures for fusing and disconnecting laterally tapped lines. The purpose of the project was to allow unencumbered use of a new golf course in the area of the overhead lines. The in service date for this underground installation was determined to be prior to the end of the test year although a precise date was not provided by UNS Electric at the time of this report. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. The customer contribution was undetermined at the time of this report and UNS Electric advised Staff on June 1, 2007 that they would provide documentation after researching the matter further.

Mohave County

1. T3 and London Bridge Substation (rate base inclusion of $2,330,038.55) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the enlargement of the existing substation and installation of a 24 MVA 69/13 kV transformer, breaker, control house and associated substation equipment in the Lake Havasu area to correct overload conditions on the initial two transformers in the substation. The in service date for this latest installation was verified to be June 29, 2005. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. Staff noted during the site visit that razor wire or barbed wire was not in place protecting the tops of the two gate entrances (as it was around all the masonry wall of the substation) and that oil containment was not present on the two earlier installed substation transformers. UNS Electric advised that they will address the gate protection issue soon and the two existing transformers will have oil containment installed when they are changed out in the next few years. Staff is satisfied with the gate response and conditionally satisfied with the oil containment response. UNS Electric should assure they are in compliance with the Environmental Protection Agency ("EPA") regulations with regard to the Spill Prevention and Countermeasure Control ("SPCC") provisions especially with a

wash immediately adjacent the substation with downhill flow to Lake Havasu approximate one mile away.

2. Install 69/20.8 kV transformer North Havasu project (rate base inclusion of $440,204.04) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the installation of a 5 MVA 69/13.2 kV transformer and associated facilities in an existing substation to address load growth in the area. The in service date for this latest installation was verified to be March 9, 2005. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition and adequate security was in place.

3. Tenant Improvements for New Maricopa (rate base inclusion of $498,260.68) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the upgrades performed on an office building to accommodate UNS Electric business and engineering office functions. The building was (and still is) leased; however the lease cost is not part of this project. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition and adequate security was in place.

4. 69 kV feeders from Havasu North (rate base inclusion of $892,991.37) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the installation of approximately one mile of double circuit 69 kV line out of Havasu North Substation. The in service date for the installation was verified to be June 27, 2006. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition. Staff initially noted the cost of the facility seemed high, close to $900,000 for one mile of 69 kV line, however the observed construction (steel poles, double circuit, drilled piers) was warranted and could reasonably raise the project cost to the actual cost incurred for this project. Staff is satisfied that the work was reasonable and prudent even with the initial planning estimate calling for the project to cost $283,000. Staff however, would generally like to see documentation (which was not available in this case) that justifies project overruns of this magnitude and new budget approval documentation before the work is started. This would, in Staff's opinion, assure that overruns did not displace or delay other more needed projects and that limited capital funds were being wisely spent.

5. Havasu North to Black Mesa Substation (rate base inclusion of $512,605.33) was initially field reviewed by Staff and UNS Electric representatives on June 6, 2007. The project involved the installation of approximately 16 miles of fiber optic

cable on existing poles between Havasu North Substation and Black Mesa Substation and associated communication control facilities at the substations. The project was part of an Agreement with Western Area Power Administration ("WAPA") related to substation control communication. The in service date for the installation was confirmed to be during November, 2005 (exact date not readily available). A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff reviewed the Havasu North termination point only and found the facility in good condition. Staff did note that the control house at Havasu North containing the communication equipment appeared to be more elaborate and more expensive in construction (masonry walls, pitch roof, removable floor in lieu of overhead cable trays) than normally expected in outdoor substations. UNS Electric advised that they were contractually bound by their contract with WAPA to build the facility to WAPA standards. Staff prefers, for economy and function, the control house construction standards noted at other UNS Electric facilities observed on the June 6, 2007 site visits, however, under the contractual circumstances with WAPA, Staff believes the likely extra cost of the project (due to control house construction to WAPA standards) is reasonable.

D. CONSCLUSIONS FOR USED AND USEFUL ASSESSMENT

All projects were determined to be used and useful no later than the dates reported by UNS Electric (subject to confirmation of the Kantor 7203 Overhead to Underground Nogales project).

The Tubac Golf Resort Overhead to Underground Conversion (Task CE64023) with a cost of $236,873.96 and inspected on May 31, 2007 had the appearance of a project that should be reimbursed at least in significant part by the customer since it involved the removal of an overhead 13 kV line and installation of an underground 13 kV line to allow for a developer's golf course. UNS Electric advised that the project appeared to be reimbursable to some extent; however they were not able to provide documentation at the review or by the morning of June 11, 2007 as requested in a follow up notification. Staff suggests this project be considered for removal in projects in rate base unless UNS Electric provides sufficient documentation to prove inclusion is appropriate.

All projects were subject to a UNS Electric approval process that insured a review by management was completed prior to construction. Staff preferred to view a project specific budget approval document for each project with justification, projected cost (company and customer itemized), changes to projected cost when anticipated, and approvals. This is a common industry practice; however, UNS Electric advised this is not their project budgeting process. Staff has no objection to any budgeting process that allows for a timely and thorough review of project cost and benefits by management and believes this was accomplished for the projects in this Used and Useful review. Staff suggests however that significant project overruns, as was apparently the case for the 69 kV feeders from Havasu North project, be more clearly identified and reviewed prior to construction to assure project overruns are evaluated and agreed to by management.

All substation sites visited were secure with enclosures of the proper height and were topped with either barbed wire or razor ribbon (except London Bridge Substation which is being addressed). All substation and line sites visited displayed construction in compliance with the National Electric Safety Code and were indicative of good utility practices.

One substation, London Bridge, should be reviewed to assure compliance with EPA SPCC regulations.

IV. CONSTRUCITON WORK IN PROGRESS ASSESSMENT

A. FRAMEWORK

A construction work in progress ("CWIP") determination requires a physical survey of new and improved facilities that are included in rate base to assure reasonable progress of construction and validation that equipment will be fully operational by a particular date. The projects included in CWIP by UNS Electric in the Rate Application were not in service at the end of the test year (June 30, 2006) but were anticipated to be in service soon thereafter. Staff therefore believed it was appropriate to review the circumstances of a representative group of CWIP projects and document those findings for further consideration of the CWIP inclusion or exclusion of CWIP in rate base.

During electric facility site visits for CWIP, Staff generally ascertains when the project was placed in service and considered used and useful after the end of the test year (June 30, 2006) or alternatively, if not used and useful, when will this most likely occur and is that reasonably close to the end of the test year. Other considerations covered in the previous Used and Useful Assessment Section III then apply if the project is determined used and useful.

Confirmation that equipment exists in the field or is on order is a determination for a CWIP determination. Therefore the operational readiness status of all onsite equipment is noted.

B. PROJECT SELECTION

Staff reviewed the listing of projects provided by UNS Electric and identified as "Net CWIP June, 2006" totaling $10.8 million after adjustments and which have been included in the rate base application. Staff selected five representative high cost projects totaling $4.2 million for further review. Two projects were selected for Santa Cruz County and three for Mohave County with a mix of Distribution, Transmission, Production and General Plant categories. The projects for both Santa Cruz County and Mohave County are listed in the attached Exhibit 4. Staff was especially interested in the process used by UNS Electric to determine the need and costs for projects and the associated approval process. Also, confirmation through an independent and directly linked document was reviewed for each project meeting the used and useful criteria after the test year to determine the plant was used and useful by a particular date. Finally, a field review of each project was conducted (or office demonstration in the case of the Information Technology project) to confirm the project was constructed or in the process of construction and fairly represented in the information presented.

C. SITE VISITS AND FIELD OBSERVATIONS

Staff prepared a checklist of issues to review and resolve with each project and these checklists are provided herein as a continuation of Exhibit 2 for Santa Cruz County and Exhibit 3 for Mohave County. A brief summary of the results from each project review is provided below:

<u>Santa Cruz County</u>

1. The Geographic Information System ("GIS") Integration Project (CWIP inclusion of $597,107.00) was satisfactorily demonstrated to Staff on May 30, 2007 at the Tucson Control Center verifying its usefulness as a tool to map and locate distribution facilities in Santa Cruz County. This tool is an integral part of the OMS described earlier to track outages and determine likely sources of trouble to expedite field dispatching and service restoration. The GIS was initially implemented under an earlier project in 2004 and this latest associated CWIP project was undertaken to refine various data points through a field review. This project was completed in April 2007 as verified through the project status report. GIS is a commonly used technology by utilities with widespread implementation in the utility industry beginning about ten years ago. UNS Electric's GIS application is similar to the GIS applications generally found with other similarly sized utilities. The application is presently used exclusively used in Santa Cruz County. Staff therefore considers the work performed through the completion of the project in April 2007 to be appropriate, however this is not a recommendation for or against including the associated CWIP cost in the rate base application.

2. The Valencia Turbine (CWIP inclusion of $1,290,669.04), located at the Valencia Substation in Nogales, is described earlier in Section III for Used and Useful projects. Additionally, this turbine project has a continuing work requirement (CWIP) associated with upgrades to the Valencia Substation to achieve the full functionality of the turbine and associated substation. Staff inspected the site on May 30, 2007 with UNS Electric representatives to review the CWIP portion of this project. UNS Electric has completed extensive bus upgrades in the Valencia Substation and plans one transformer upgrade in the Fall of 2007 and further breaker upgrades through the Spring of 2008. Staff recognizes that substation upgrades performed after close of the test year (June 30, 2006) and as planned at Valencia Substation after this date are common when a generating source is added in close proximity to a substation and is necessary to achieve the full capability of the facility. Staff therefore considers the work performed to date and through the completion of the project in the Spring of 2008 to be appropriate, however this is

not a recommendation for or against including the associated CWIP cost in the rate base application.

Mohave County

1. West Golden Valley Substation (CWIP inclusion of $1,220,855.18) was initially field reviewed by Staff and UNS Electric representatives on June 7, 2007. The project involved the construction of a complete and new 69 kV supplied substation with one 20 MVA 69/21 kV transformer, two outgoing 21 kV feeders and associated facilities to address load growth in the area. The in service date for this latest installation was verified to be November 29, 2006. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition and adequate security was in place. Staff therefore considers the work performed through the completion of the project on June 7, 2007 to be appropriate, however this is not a recommendation for or against including the associated CWIP cost in the rate base application.

2. Rhodes Homes (CWIP inclusion of $442,254.92) was initially field reviewed by Staff and UNS Electric representatives on June 7, 2007. The project involved the installation of approximately five miles of 21 kV overhead line to supply service to water pumps for a proposed housing development. The in service date for this latest installation was verified to be May 26, 2006 which was prior to the end of the test year and therefore eligible for Used and Useful plant treatment. This project is fully funded initially by the customer (Rhodes Homes) with UNS Electric refunding the cost under an agreement based on actual revenues received from this new service (refer to March 2, 2006 Letter of Agreement). A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition. Staff therefore considers the work performed through the completion of the project on May 26, 2006 to be appropriate and should be considered for Used and Useful treatment with allowance for the customer advance described.

3. Griffith 230 kV Sub 230 kV line (CWIP inclusion of $613,584.64) was initially field reviewed by Staff and UNS Electric representatives on June 7, 2007. The project involved the construction of a new 230 kV/69 kV double circuit line 35 miles in length between the Griffith Generating plant and North Havasu substation. Staff observed with the UNS Electric representative the North Havasu to Franconia 69 kV portion of this project reportedly complete in July, 2006. The majority of the project, the 230 kV line to Griffith Generating plant has been deferred until 2012 or later. A review of available documentation confirmed that this project was authorized and constructed in an appropriate manner. During the site visit, Staff found the facility in good condition. Staff therefore considers the

work performed through the completion of a portion of the project in July, 2006 to be appropriate, however this is not a recommendation for or against including the associated CWIP cost in the rate base application.

D. CONSCLUSIONS FOR CWIP ASSESSMENT

All projects were determined to be appropriately included in CWIP as of June 2006 although one project, Rhodes Homes which was put in service just prior to the CWIP accounting, could reasonably qualify for Used and Useful treatment. Three of the projects have been completed since the June 2006 CWIP determination (GIS, West Golden Valley and Rhodes Homes) and two projects are continuing (Valencia and Griffith).

All projects were subject to a UNS Electric approval process that insured a review by management was completed prior to the start of construction.

All substation sites visited were secure with enclosures of the proper height and were topped with either barbed wire or razor ribbon.

One project, Rhodes Homes 21 kV supply, was in service on May 26, 2006 which was prior to the end of the test year and therefore eligible for Used and Useful consideration. The project also had a 100% customer advance repayable by UNS Electric when certain load conditions developed.

Staff considers the work performed on all projects in this CWIP review to be appropriate; however, this is not a recommendation for or against including the associated CWIP cost in the rate base application.

V. BLACK MOUNTAIN GENERATING STATION REVIEW

A. FRAMEWORK

UNS Electric has proposed the addition of the future Black Mountain Generating Station ("BMGS") in the rate base application. Pre-filed testimony indicates this new generating station will be a 90 megawatt ("MW") facility located in Mohave County with an expected in service date of 2008 and an estimated cost of $60 million to $65 million. Staff believed it was appropriate and expeditious to conduct a high level review of this facility in conjunction with other office and site reviews described in this report to provide additional information on this project. A check list provided as a continuation of Exhibit 3 was utilized to conduct the review.

B. OFFICE and SITE VISIT OBSERVATIONS

Staff reviewed office records with UNS Electric on June 1, 2007 describing Board of Director's recommendations for the construction of BMGS at a cost of $60 million inclusive of two new 45 MW gas fired simple cycle generators (Consolidated Edison surplus), transmission line interconnection facilities and gas line supply construction. Staff was further advised that approximately $41 million has been spent to date for purchase of the two turbines, transformers, engineering, materials and generator modification cost. The two turbines are reportedly in Texas undergoing the necessary modifications for use in this application. The remaining equipment is reportedly still with the manufacturers in various stages of completion. The only confirmed fact regarding equipment for this project was that none of the equipment was on site at the time of the June 6, 2007 field review.

Staff did review the site with UNS Electric on June 6, 2007. The site is in open desert south of Kingman off Interstate 10 and less than five miles south of the existing Griffith Generating Plant. The site was reportedly owned previously by Citizens Electric and transferred to UNS Electric. It has a 69 kV line existing on the road frontage of the property which will be used (at least in part) for connection of the plant to the transmission grid. A gas line installation for the plant was in progress on the road frontage and through a portion of the property during the June 6, 2007 site visit. No electrical equipment (or equipment of any kind) was installed or stored on the site at the time of the site visit other than the 69 kV line and gas line previously mentioned.

C. CONSCLUSIONS FOR BMGS

Staff offers only the above observations regarding BMGS as part of the general review of other issues in the area. Staff makes no recommendation for or against inclusion of BMGS in the rate base application.

EXHIBIT 1

Used and Useful Review Projects for Arizona Corporation Commission (Docket E-04204A-06-0783)--May 7, 2007

Territory	Project	Proj Description	Task	Task Description	Raw Cost	Date In Service	ACC Comments
MOHAVE Distribution	360062S	T3 Lond Brdg Sub & Wall Expan	HH11317	T3 Lond Brdg Sub & Wall Expan	2,330,038.55	27-Sep-2003	field insp
MOHAVE Distribution	352062S	Install 69/20.8kv Xfmr N Havasu S	HH11315	Install 69/20.8kV, 5MVA T2 Transformer	440,204.04	29-Jan-2006	field insp
MOHAVE General Plant	310062A	Office Furn & Equip-New (LH)	HH10778	Tenant Improvements for New Maricopa Facility, 2749 Maricopa	498,260.68	31-Oct-2004	field insp
MOHAVE Transmission	325061I	69kV Fdrs from Havasu N (King)	7006537	69KV FEEDERS FROM HAVASU NORTH	892,991.37	27-Jun-2006	field insp
MOHAVE Transmission	350062S	North Havasu to BMS Redundant	CE62052	North Havasu Sub to Black Mesa Sub	512,605.33	13-May-2005	field insp
SANTA CRUZ Distribution	366064S	Kantor 7203 OH to UG Nog	141524	Amado- Montosa Road Amado, AZ 85645	333,333.86	12-Feb-2006	field insp
SANTA CRUZ Distribution	302064A	Line Extensions > $10,000(Nog)	CE64023	2003-Tubac Golf Resort - O/H to U/G	236,873.96	16-Oct-2005	field insp
SANTA CRUZ General Plant	322064A	Systems Integr Projects (Nog)	CD1252C	Integrate OMS with UNSE SC	142,944.30	27-Jan-2005	offcie review
SANTA CRUZ Production	383064A	UNSE Valencia Turbine 4	HS10536	Valencia Addition Turbine 4	12,169,026.94	30-Jun-2006	office review
SANTA CRUZ Transmission	363064A	Canoa/Kantor Line	HS10188	46kV Line Construction Canoa to Kantor	2,282,720.61	13-Mar-2005	office review
Grand Total					19,838,999.64		

Revision #1

Checklist for ACC Santa Cruz Project Review May 30 and 31, 2007
UNS Electric (Docket E-04204A-06-0783)

Used and Useful

1. OMS Integration Project (Task CD1252C)
    a. Demonstration
    b. Review office records
        i. verify in service date
        ii. project scope and approval
    c. Determine Mohave and Santa Cruz applications
    d. Determine link to Reliability Measures (SAIDI, SAIFI, etc)

2. Valencia turbine (Task HS10536)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. What were Valencia turbine alternatives?
    c. How was decision made to proceed with this alternative?

3. 46kV Canoa to Kantor line(Task HS10188)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. How often is this line utilized (hours/ year, events/year, etc.)?
    c. What alternatives were considered in lieu of this line?

4. Kantor 7203 OH to UG Nogales project (Task 141524)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

5. Tubac Golf Resort OH to UG project (Task CE64023)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Customer contribution?
    d. Field review of project

CWIP

6. GIS Integration Project (Task CD1250C)
    a. Demonstration
    b. Review office records
        i. verify in service date
        ii. project scope and approval
    c. Determine Mohave and Santa Cruz applications
    d. Determine link to OMS
    e. Determine link to Reliability Measures (SAIDI, SAIFI, etc)

7. Valencia Turbine (Task HS10536)
    a. Cost incurred after in service date comprises what?
    b. When will capital portion of project be complete?
    c. What was initial approved cost of this turbine project?
    d. What is the final expected cost of this turbine project?
    e. Explain if final cost expected to be greater than 10% of initial approved cost.
    f. What is final expected $/MW for this turbine?
    g. How does $/MW compare to industry averages for similar construction?
    h. Field review of project CWIP if necessary

MISCELLANEOUS

8. Worst performing distribution feeders (2005-2006) — field review
    a. Canez C-8203 serving N Pendleton Dr

Revision #1

Checklist for ACC Mohave Project Review June 5 and 6, 2007
UNS Electric (Docket E-04204A-06-0783)

Used and Useful

1. T3 Lond Brdg Sub & Wall Expan project (Task HH11317)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

2. Install 69/20.8kv xfmr N Havasu project (Task HH11315)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

3. Tenant Improvements for New Maricopa (Task HH10778)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

4. 69 kV feeders from Havasu North (Task 7006537)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

5. North Havasu to BMS (Task CE64023)
    a. Review office records
        i. verify in service date
        ii. project scope and approval
    b. Verify need for project (how determined)
    c. Field review of project

CWIP

6. West Golden Valley Sub (Task HK10487)
    a. Review office records
        i. Determine expected in service date
        ii. project scope and approval
    b. What is the final expected cost of the project
    c. Verify need for project (how determined)
    d. Field review of project

7. Rhodes Homes (Task 8009729)
    a. Review office records
        i. Determine expected in service date
        ii. project scope and approval
    b. What is the final expected cost of the project
    c. Verify need for project (how determined)
    d. Customer contribution?
    e. Field review of project

MISCELLANEOUS

8. Proposed Black Mountain Generating Station
    a. Review office records
        i. Determine expected in service date
        ii. project scope and approval
    b. What is the basis of the projected $60 million to $65 million cost of the project?
    c. Have funds been expended in CWIP through June 30, 2006? After June 30, 2006?
    d. Verify need for project (how determined)
    e. Field review of project site

9. Worst performing distribution feeders (2004-2006) — field review
    a. No 8008 serving Aqua Fria and Golden Valley
    b. No 8016 serving Aqua Fria and Golden Valley
    c. No 6026 serving Lake Havasu

EXHIBIT 4

UNSE, Inc.
ACC STF 2.2
25-Apr-2007

CWIP Review Projects for Arizona Corporation Commission (Docket E-04204A-06-0783)--May 7, 2007

Territory and Category	Project	Project Description	Task Number	Task Description	Cost	Delayed Plant Jun-06	Net CWIP Jun-06	Unitized Jul-06 to Mar-07	Delayed Plant Mar-07	6/30/06 CWIP not in Service as of 3/31/07	Date In Service	Projected In-Service Date
SANTA CRUZ Production	383064A	UNSE Valencia Turbine 4	HS10536	Valencia Addition Turbine 4	13,598,826.00	12,308,156.96	1,290,669.04	13,323,926.23	-	-	30-Jun-2006	
MOHAVE Distribution	330061S	West Golden Valley Subst Kir	HK10847	West Golden Valley Subs	1,220,855.18	-	1,220,855.18	-	2,132,570.33	-	1-Dec-2006	
MOHAVE Distribution	333061A	Line Extensions > $50K King	8009729	RHODES HOMES ARIZONA / GV \	442,254.92	-	442,254.92	-	436,858.34	5,396.58	28-May-2006	
SANTA CRUZ General Plant	322064A	Systems Integr Projects (Nog	CD1250C	Integrate GIS with UNSE SC	597,107.00	-	597,107.00	-	-	597,107.00		Jun-07
MOHAVE Transmission	327062I	Griff to N Hav Sub 230kV (LH	CE62047	Griffith 230kV Sub 230kV Line (LH)	613,584.64	-	613,584.64	-	-	613,584.64		Jul-07
					16,472,627.74	12,308,156.96	4,164,470.78	13,323,926.23	2,569,428.67	1,216,088.22		

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

On December 15, 2006, UNS Electric, Inc. ("UNS") filed an application with the Arizona Corporation Commission ("Commission") for an increase in its rates throughout the State of Arizona. In addition, UNS proposes to change the existing Customer Assistance Residential Energy Support ("CARES") and Customer Assistance Residential Energy Support Medical programs from volumetric discounts to a flat discount of $8.00.

1. Staff recommends that UNS Electric work with the Arizona Health Care Cost Containment System ("AHCCCS") to ensure that AHCCCS participants eligible for Medical CARES discounts are made aware of the UNS Electric program.

2. Staff recommends that the current discount structures be retained for the CARES and CARES Medical classes.

3. Staff recommends that an adjustment to test year data be made in order to reflect Staff's recommendations regarding Residential rates.

4. Staff recommends a $400 limit per year, per household, for the UNS Electric Warm Spirits emergency bill assistance program, to conform with the UNS Gas program and to allow more households in crisis to benefit from this funding.

5. Staff also recommends that UNS Electric set the following additional eligibility requirements, in conformance with the UNS Gas program: (i) a household income of 150 percent, or less, of the Federal Poverty Guidelines; (ii) a UNS Electric utility customer; (iii) a delinquent or unpaid UNS Electric utility bill; and (iv) no Warm Spirits emergency bill assistance received in the previous 12 months. (UNS Gas, Gary A. Smith, p. 12)

6. Staff recommends that community action agencies administering the emergency bill assistance funding have flexibility in determining how much to provide to each household, up to the $400 limit.

7. Staff also recommends that, if the Warm Spirits program is approved, UNS Electric work to create awareness of the emergency bill assistance available under the program, so that eligible customers will know of this resource before they are facing disconnection for non payment, as discussed in the next section.

8. Staff recommends that the $20,000 proposed for the emergency bill assistance component of the Low-income Weatherization program be added, instead, to the Warm Spirits program. Staff also recommends that the $20,000 be funded through base rates, rather than through the DSM adjustor.

9. Staff recommends that non-CARES Residential customers experiencing difficulty paying utility bills be informed of the CARES program and of the Medical CARES and low-income weatherization programs, if those would be appropriate. Staff also recommends that non-CARES Residential customers be made aware of the Warm Spirits program, if that program is approved by the Commission.

10. Staff recommends that CARES customers experiencing difficulty paying utility bills be informed of the Warm Spirits emergency bill assistance program, if that program is approved, and of the Medical CARES and low-income weatherization programs, if those are appropriate.

11. Staff recommends that UNS Electric provide additional information concerning the above disconnections, and regarding any procedures the Company has in place to ensure that the provisions of R14-2-211 are complied with. Staff also recommends that Medical CARES customers having difficulty paying their utility bills be made aware of the low-income weatherization program, and of the Warm Spirits program, if that program is approved by the Commission.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst II.

A. In my capacity as a Public Utilities Analyst II, I review monthly filings of purchased gas adjustors. My duties include reviewing annual utility affiliated interest reports for compliance and evaluating demand-side management programs submitted for approval to the Commission. My duties have also included preparing written testimony in the UNS Gas rate case, as well testifying during the UNS Gas rate case hearing.

Q. Please describe your educational background and professional experience.

A. In 1979, I graduated magna cum laude from Arizona State University, receiving a Bachelor of Arts degree in History. In 1987, I received a Master's Degree in Political Science from the University of Wisconsin, Madison. I have been employed by the Commission since September of 2006.

Q. What is the subject matter of this testimony?

A. This testimony will present Staff's analysis and evaluation of UNS Electric, Inc.'s ("UNS Electric") existing low-income assistance programs and the proposed changes to those programs. This testimony will also include discussion and analysis of the Company's proposal to add an emergency bill assistance component to its Low-income Weatherization ("LIW") program, as well as its proposal to create a Warm Spirits program for UNS Electric.

LOW-INCOME ASSISTANCE PROGRAMS

CARES and Medical CARES

Q. What low-income assistance programs does UNS currently provide for its customers?

A. UNS provides the Customer Assistance Residential Energy Support ("CARES") program and Medical Customer Assistance Residential Energy Support ("Medical CARES") program. (Thomas J. Ferry, p. 9-10)

Q. Please describe the eligibility requirements for the current CARES program.

A. To be eligible for the UNS Electric CARES program a household's gross income must be at, or below, 150 percent of the Federal Poverty Guidelines. The FPG guidelines establish poverty levels for households based on the number of individuals in each household. For 2007, the annual FPG level for a household with four persons is $20,650; 150 percent of $20,650 is $30,975 annually, or $2,581 per month. (Thomas J. Ferry; p. 9; 2007 Health and Human Services Poverty Guidelines)

Q. Please describe the application process for the CARES program.

A. Low-income customers must submit an application to qualify for the CARES program to UNS Electric. Originally, the Department of Economic Security processed applications, and enrollment took up to 45 days. Due to program modifications authorized by the Commission in 2004, applications are processed in-house and low-income customers can now be enrolled in CARES in less than 20 days. In addition, customers are no longer required to recertify themselves on an annual basis. Instead, UNS Electric recertifies a sample group of participants every two years and when a customer changes residence. (Thomas J. Ferry, p. 9; Decision No. 67434)

Q. How many UNS Electric customers participate in the CARES program and how has participation changed over time?

A. Average participation for the six months ending December 2006 was 5,985, or 7.56 percent of Residential customers. Average participation for the six months ending December 2004 was 5,157, or 7.18 percent of Residential customers. (UNS Electric, Inc. CARES Discount Program semi-annual reports.) Over two years this represents an increase of 16 percent in the number of participants, although participation as a percentage of Residential customers has remained relatively steady.

Q. Please describe the discounts currently offered under the CARES program.

A. The CARES program provides declining tiered percentage discounts. The discount is 30 percent for bills with usage from 0 to 300 kWh, 20 percent for bills with usage of 301 to 600 kWh and 10 percent for bills with usage of 601-1,000 kWh. CARES customers using over 1,000 kWh receive a flat $8.00 discount. (Thomas J. Ferry, pp. 9-10; Schedule H-4)

The total level of usage determines the discount applied to all kWh used. For example, to receive a 30 percent discount a CARES customer must use 300 kWh or less in a month. If a CARES customer uses 301 kWh, the amount of the discount decreases to 20 percent for all 301 kWh used.

Q. Please describe the eligibility requirements and application process for the current Medical CARES.

A. Customers must submit an application to UNS Electric, along with verification from a physician that they are dependent on medical life-support equipment. This physician-verification is required in addition to the CARES eligibility standard that household income be at, or below, 150 percent of the Federal Poverty Guidelines. (Thomas J. Ferry, pp. 9-10; Schedule H-4; Tariff No.: C.A.R.E.S. – M, Effective December 3, 2004)

The types of medical support equipment that qualify as essential under the Medical CARES program include the following: (i) Ventilator; (ii) Oxygen Concentrator; (iii) Peritoneal Dialysis Cycler; (iv) Hemo Dialysis Equipment; (v) Feeding Pump; (vi) Infusion Pump; (vii) Suction Machine; (ix) Small Volume Nebulizer; and (x) Oximeter. (Tariff No.: C.A.R.E.S. – M, Effective December 3, 2004)

Q. How many UNS Electric customers participate in the Medical CARES program?

A. UNS Electric states that, as of March 2007, there were 178 Medical CARES participants. With 80,327 Residential customers reported as of March 2007, Medical CARES customers represent 0.22 percent of Residential customers. (Response to STF 5.7; March 2007 UNS Electric Bank Balance Report FA-3.)

Staff recommends that UNS Electric work with the Arizona Health Care Cost Containment System ("AHCCCS") to ensure that AHCCCS participants eligible for Medical CARES discounts are made aware of the UNS Electric program.

Q. Does the current Medical CARES program offer discounts different from those offered under the standard CARES program? If so, please describe the discounts currently offered under the Medical CARES program.

A. Yes, under the current Medical CARES program the tiered percentage discounts are tied to usage ranges that are twice those offered under the standard CARES program. The Medical CARES program provides monthly discounts of 30 percent for bills with usage from 0-600 kWh (0-300 kWh under standard CARES), 20 percent for bills with usage from 601-1,200 kWh (301-600 kWh under standard CARES), 10 percent for bills with usage from 1,201-2,000 kWh (601-1,000 kWh under standard CARES). There is a flat $8.00 discount for usage over 2,000 kWh. (Under standard CARES the flat $8.00 discount applies after 1,000 kWh.) (Thomas J. Ferry, p 9-10; www.uesaz.com)

As with the standard CARES program, the total level of usage by a Medical CARES customers determines the discount applied to the entire bill. For example, while a Medical CARES customer using 1,200 kWh would receive a 20 percent discount for all 1,200 kWh, a Medical CARES customer using 1,201 kWh would receive a 10 percent discount for all 1,201 kWh.

Q. Does the discount proposed by UNS Electric provide different discounts to CARES and Medical CARES customers?

A. No. In his testimony, Mr. Ferry indicates that UNS Electric proposes to eliminate the volumetric discount for both CARES and Medical CARES and to apply a "universal" discount of $8.00 (or less than $8.00 for bills under that amount).

Q. Should Medical CARES customers receive discounts different from those provided to standard CARES customers?

A. Yes. While Medical CARES and standard CARES customers are both low-income, Medical CARES are also: (i) dependent upon medical equipment; and (ii) have average usage rates higher than those for either standard CARES or non-CARES Residential customers.

Q. How many kWh do CARES, Medical CARES and non-CARES Residential customers use on average?

A. The averages from the test year are as follows:

- On an annual basis, the average CARES customer uses 744 kWh per month, ranging from a low of 520 kWh to a high of 1,009 kWh.
- On an annual basis, the average Medical CARES customer uses 1,113 kWh per month, ranging from a low of 780 kWh to a high of 2,498 kWh per month.
- On an annual basis, the average non-CARES Residential customer uses 869 kWh per month, ranging from a low of 592 kWh to a high of 1,281 per month.

(Response to STF 5.6)

Q. Why is kWh usage by CARES Medical customers higher than for other CARES or non-CARES Residential customers?

A. UNS Electric states that it has done no studies regarding the differing usage rates for CARES, Medical CARES and non-CARES Residential customers. (Response to STF 12-4.) Decision No. 67434 states that the Medical CARES program provides bill discounts for UNS Electric customers "at higher consumption levels when the customer requires the use of medical equipment for sustaining life and a physician verifies the situation."

Q. What percentage of CARES and Medical CARES bills qualify for percentage discounts, based on usage under 1,000 kWh for CARES customers, and 2,000 kWh for Medical CARES customers?

A. The bill frequency provided by UNS Electric does not break out Medical CARES customers (under 200 participants). For the combined CARES/Medical CARES class, 83.83 percent of customer bills were for 1,000 kWh, or less. (Schedule H-5, pp. 1-2) The small number of Medical CARES customers would be eligible for percentage discounts up to 2,000 kWh.

Q. Does UNS propose to change the CARES program discount?

A. Yes. Under the UNS Electric proposal, the declining tiered percentage discounts would be eliminated. As stated elsewhere in this testimony, UNS proposes a flat monthly CARES discount of $8.00 on all bills that total $8.00 or more. CARES customers with bills totaling less than $8.00 would receive lower discounts; those discounts would equal the amount of the bills. (UNS states that fewer than 2.51 percent of CARES bills total less than $8.00.) (Bentley Erdwurm, p.24; UNS Response to STF 5.5; Schedule H-5, p. 2 of 7)

Q. Do the proposed CARES and Medical CARES discounts promote conservation as well as the current discounts?

A. No. A flat discount applied to all bills, regardless of usage, does not provide the same incentive to conserve as the current declining tiered percentage discount. The current discount provides the highest percentage discount for the lowest usage rates, and provides progressively lower discounts for progressively higher usage rates. Under a flat discount, customers would receive the same discount, without regard to their energy consumption. (The one exception to the flat rate is that customers with kWh charges amounting to less than $8.00 would receive discounts equal to those lower amounts.)

Q. What would be the impact on customer bills of the discount changes proposed by UNS Electric?

The below tables provide bill impacts, based on current UNS Electric rates, for CARES and Medical CARES customers with average usage; the tables cover both Mohave and Santa Cruz County.

CARES Bills at Average Levels of Usage (Mohave County)

Averages	Usage	With Current Discount	With UNS Proposed Discount	Increase/ Decrease	Percentage Change
Lowest Monthly	520	$43.95	$46.94	$2.99	6.80%
Highest Monthly	1,009	$92.49	$92.49	$0.00	0.00%
Annual	744	$68.20	$67.80	($0.40)	($0.59%)

CARES Bills at Average Levels of Usage (Santa Cruz County)

Averages	Usage	With Current Discount	With UNS Proposed Discount	Increase/ Decrease	Percentage Change
Lowest Monthly	520	$45.78	$49.23	$3.45	8.00%
Highest Monthly	1,009	$96.93	$96.93	$0.00	0.00%
Annual	744	$71.17	$71.08	($0.09)	($0.13%)

Medical CARES Bills at Average Levels of Usage (Mohave County)

Averages	Usage	With Current Discount	With UNS Proposed Discount	Increase/ Decrease	Percentage Change
Lowest Monthly	738	$60.20	$60.74	$0.54	0.90%
Highest Monthly	2,498	$231.19	$231.198	$0.00	0.00%
Annual	1,113	$88.14	$95.68	$7.54	8.55%

Medical CARES Bills at Average Levels of Usage (Santa Cruz County)

Averages	Usage	With Current Discount	With UNS Proposed Discount	Increase/ Decrease	Percentage Change
Lowest Monthly	738	$62.79	$70.49	$7.70	12.26%
Highest Monthly	2,498	$242.18	$242.18	$0.00	0.00%
Annual	1,113	$92.06	$107.07	$15.01	16.30%

A different rate structure for Residential customers would shift the impact of UNS Electric's proposed discount changes. For example, under the Residential rate changes proposed by

UNS Electric, the largest impacts would be to Medical CARES customers with usage from 400 kWh to 1,000 kWh. Under the UNS Electric proposed rates these increases would range from 12.13 percent to 27.94 percent for customers in both Mohave and Santa Cruz County. (Response to STF 12-5)

Q. Why is the impact of UNS Electric's proposed changes different for Santa Cruz County than for Mohave County customers?

A. Under existing rates there is a per-kWh energy charge of $0.0749 for all Mohave County Residential customers and a per-kWh energy charge of $0.0793 for all Santa Cruz County Residential customers. Under the rate proposal put forward by UNS Electric, Residential customers in both counties would be covered by the same rates, which also affect CARES/Medical CARES customers.

Q. Does Staff recommend the proposed changes to the CARES and Medical CARES discounts?

A. No. The proposed changes to the CARES and Medical CARES discounts would eliminate the incentive to conserve provided by the existing discount structure, and would generally have a larger negative impact on CARES Medical customers with low-average, or average, usage, and on CARES customers with low-average usage.

Staff recommends that the current discount structures be retained for the CARES and CARES Medical classes.

Q. Would an adjustment to test year data be required with respect to the CARES discount proposed by UNS Electric?

A. Yes. The CARES Expense noted on Schedule-2, -$52,937, Page 1 of 5, reflects UNS Electric's proposed changes to the CARES and Medical CARES programs.[1] (Dallas J. Dukes, p. 7; Response to STF 5.1) This amount should be removed and replaced with an amount calculated using the discounts recommended by Staff. Staff will recommend that final amount to be used for the adjustment once Staff makes its recommendations regarding Residential rates.

Staff recommends that an adjustment to test year data be made in order to reflect Staff's recommendations regarding Residential rates.

Warm Spirits

Q. Please describe the Warm Spirits program, as proposed by UNS Electric.

A. The proposed UNS Electric Warm Spirits program is modeled on the existing UNS Gas Warm Spirits program. The UNS Electric program would provide emergency bill assistance to low-income customers in crisis. The proceeds would be distributed by community action agencies. Under the UNS Electric proposal, the community action agencies would determine which customers would receive assistance and how much.

Q. Does Staff have any recommendations concerning the proposed Warm Spirits program?

A. Yes. Staff recommends a $400 limit per year, per household, for the UNS Electric Warm Spirits emergency bill assistance program, to conform with the UNS Gas program and to allow more households in crisis to benefit from this funding. Staff also recommends that

[1] Test year CARES discount = $532,009 - $584,937 (normalized CARES bills = 73,118 x $8.00 flat discount = $584,937) = ($52,937).

UNS Electric set the following additional eligibility requirements, in conformance with the UNS Gas program: (i) a household income of 150 percent, or less, of the Federal Poverty Guidelines; (ii) a UNS Electric utility customer; (iii) a delinquent or unpaid UNS Electric utility bill; and (iv) no Warm Spirits emergency bill assistance received in the previous 12 months. (UNS Gas, Gary A. Smith, p. 12.) The above requirements would be in addition to the requirements for establishing that a customer is in crisis, including loss of reduction of income, unexpected expenses and a danger to the health or safety of the household (Thomas J. Ferry, P. 19)

Staff recommends that community action agencies administering the emergency bill assistance funding have flexibility in determining how much to provide to each household, up to the $400 limit.

Staff also recommends that, if the Warm Spirits program is approved, UNS Electric work to create awareness of the emergency bill assistance available under the program, so that eligible customers will know of this resource before they are facing disconnection for non payment, as discussed in the next section.

Q. What is the proposed funding for the Warm Spirits program?

A. UNS Electric has proposed that its Warm Spirits program be funded through donations from ratepayers, and matched, up to $25,000, by shareholder donations. (Thomas J. Ferry, p. 11.)

Staff recommends that the $20,000 proposed for the emergency bill assistance component of the Low-income Weatherization program be added, instead, to the Warm Spirits program. (Thomas J. Ferry, p 19) Staff also recommends that the $20,000 be funded through base rates, rather than through the DSM adjustor, as proposed by UNS Electric.

Q. Please explain why Staff is proposing to move the emergency bill assistance funding into the Warm Spirits program, and why Staff recommends that this funding not be included in the DSM adjustor.

A. UNS Electric has proposed that the Low-income Weatherization ("LIW") program be included as part of its DSM portfolio. Emergency bill assistance, although a benefit for customers in crisis situations, is a low-income assistance program and should not be included in the DSM portfolio. There are several negative consequences to including emergency bill assistance within a DSM portfolio:

(i) UNS has proposed a separate DSM charge. If emergency bill assistance is funded through a separate DSM adjustor it may not be clear to ratepayers that they are also paying for a non-DSM program through the DSM charge;

(ii) funding a non-DSM program through a DSM adjustor reduces clarity regarding the total funding level for actual DSM programs; and

(iii) inclusion of non-DSM program components within the DSM portfolio could reduce clarity regarding the objectives of DSM.

DISCONNECTIONS

Q. How many non-CARES Residential customers were disconnected during the test year?

A. UNS Electric reports 1,171 disconnections for nonpayment of non-CARES Residential customers from July 2005 through June 2006. UNS Electric reported an average of 69,492 non-CARES Residential customers for this same period. (Responses to STF 5.6 and 5.11)

Staff recommends that non-CARES Residential customers experiencing difficulty paying utility bills be informed of the CARES program and of the Medical CARES and low-income weatherization programs, if those would be appropriate. Staff also recommends that non-CARES Residential customers be made aware of the Warm Spirits program, if that program is approved by the Commission.

Q. How many CARES customers were disconnected for non-payment during the test year?

A. UNS Electric reports 117 disconnections for nonpayment of CARES customers from July 2005 through June 2006. Average CARES participation for that period was 5,792. (Responses to STF 5.6 and 5.11.)

Staff recommends that CARES customers experiencing difficulty paying utility bills be informed of the Warm Spirits emergency bill assistance program, if that program is approved, and of the Medical CARES and low-income weatherization programs, if those are appropriate.

Q. Have there been any recent disconnections for nonpayment of Medical CARES participants?

A. During the period from July 2005 through June 2006, UNS Electric reports six disconnections of Medical CARES customers for nonpayment. The average number of Medical CARES participants during this period was 147. There were an additional two such disconnections in the nine months ending March 2007). (Responses to STF 5.6 and 5.11.)

Staff is very concerned about these disconnections of Medical CARES participants and has asked UNS Electric for more information about them.

Q. Are there Arizona Administrative Code rules regulating disconnections of customers with medical issues?

A. Yes. R14-2-211.A.5 states that residential service shall not be terminated "where the customer has an inability to pay and:

"a. The customer can establish through medical documentation that . . .termination would be especially dangerous to the health of a customer or a permanent resident residing on the customer's premises, or

"b. Life supporting equipment used in the home that is dependent on utility service for operation of such apparatus."

Staff recommends that UNS Electric provide additional information concerning the above disconnections, and regarding any procedures the Company has in place to ensure that the provisions of R14-2-211.A.5 are complied with. Staff also recommends that Medical CARES customers having difficulty paying their utility bills be made aware of the low-income weatherization program, and of the Warm Spirits program, if that program is approved by the Commission.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. Staff recommends that UNS Electric work with the Arizona Health Care Cost Containment System ("AHCCCS") to ensure that AHCCCS participants eligible for Medical CARES discounts are made aware of the UNS Electric program.

2. Staff recommends that the current discount structures be retained for the CARES and CARES Medical classes.

3. Staff recommends that an adjustment to test year data be made in order to reflect Staff's recommendations regarding Residential rates.

4. Staff recommends a $400 limit per year, per household, for the UNS Electric Warm Spirits emergency bill assistance program, to conform with the UNS Gas program and to allow more households in crisis to benefit from this funding.

5. Staff also recommends that UNS Electric set the following additional eligibility requirements, in conformance with the UNS Gas program: (i) a household income of 150 percent, or less, of the Federal Poverty Guidelines; (ii) a UNS Electric utility customer; (iii) a delinquent or unpaid UNS Electric utility bill; and (iv) no Warm Spirits emergency bill assistance received in the previous 12 months. (UNS Gas, Gary A. Smith, p. 12)

6. Staff recommends that community action agencies administering the emergency bill assistance funding have flexibility in determining how much to provide to each household, up to the $400 limit.

7. Staff also recommends that, if the Warm Spirits program is approved, UNS Electric work to create awareness of the emergency bill assistance available under the program, so that eligible customers will know of this resource before they are facing disconnection for non payment, as discussed in the next section.

8. Staff recommends that the $20,000 proposed for the emergency bill assistance component of the Low-income Weatherization program be added, instead, to the Warm Spirits program. Staff also recommends that the $20,000 be funded through base rates, rather than through the DSM adjustor.

9. Staff recommends that non-CARES Residential customers experiencing difficulty paying utility bills be informed of the CARES program and of the Medical CARES and low-income weatherization programs, if those would be appropriate. Staff also recommends that non-CARES Residential customers be made aware of the Warm Spirits program, if that program is approved by the Commission.

10. Staff recommends that CARES customers experiencing difficulty paying utility bills be informed of the Warm Spirits emergency bill assistance program, if that program is approved, and of the Medical CARES and low-income weatherization programs, if those are appropriate.

11. Staff recommends that UNS Electric provide additional information concerning the above disconnections, and regarding any procedures the Company has in place to ensure that the provisions of R14-2-211 are complied with. Staff also recommends that Medical CARES customers having difficulty paying their utility bills be made aware of the low-income weatherization program, and of the Warm Spirits program, if that program is approved by the Commission.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING	DOCKET NO. E-04204A-06-0783

DIRECT

TESTIMONY

OF

BING E.YOUNG

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2007

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ATTACHMENT

RESUME 1

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783

In reviewing UNS' proposed Rules and Regulations, Staff recommends that UNS be required to re-file its line extension tariff within 30 days that eliminates the free footage allowance for new construction.

Staff additionally recommends that the Commission take no action in this proceeding with regard to hook-up fees, but defers to the generic proceeding.

Lastly, Staff recommends that UNS be required to file a bill estimation tariff containing specific methodologies for calculating estimates for various situations as described in my testimony, and that this tariff be filed with the Commission within 30 days of a final opinion and order.

I. INTRODUCTION AND STATEMENT OF WITNESS QUALIFICATION

Q. Please state your name, occupation, and business address.

A. My name is Bing E. Young. I am a Public Utility Analyst IV employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utility Analyst.

A. In my capacity as a Public Utility Analyst, I provide analysis and recommendations to the Commission on a range of issues related to the electric and telecommunications industries.

Q. Please describe your educational background and professional experience.

A. I have a Juris Doctorate (Law) degree from the University of Idaho and a Bachelor of Science degree in Geography from Brigham Young University. I was admitted to the Idaho State Bar in 1986, the Nevada State Bar in 1987, and the Utah State Bar in 2000. My professional work experience is summarized in my attached resume, Attachment 1.

Q. Are you presently licensed to practice law in Arizona?

A. No. I am not licensed to practice law in Arizona. I am, however, a member in good standing of the State Bar of Nevada and the Utah State Bar, though inactive in both states.

Q. What is the purpose of your testimony?

A. My primary focus in this case is to address certain changes to rules and regulations proposed by UNS, including line extensions; hookup fees; and bill estimation procedures.

II. RULES, REGULATIONS, AND LINE EXTENSION POLICIES

Q. Has UNS proposed any modifications to its Rules, Regulations, and Line Extension Policies?

A. Yes. UNS has proposed numerous modifications to its Rules and Regulations. UNS' existing rules are largely those that it inherited when UniSource Energy, the parent company of Tucson Electric Power Company ("TEP"), purchased Citizens Electric's Arizona assets and associated service territories. A large number of these changes are intended to make the UNS Rules and Regulations roughly analogous to those of TEP.

Q. Does Staff support the various modifications?

A. Staff supports or has no objection to many of the modifications. The ones Staff is concerned with are noted below.

Q. What modifications to the Rules and Regulations is Staff addressing?

A Staff is particularly concerned with the proposed changes UNS seeks to make to its line extension tariff and bill estimation procedures.

III. UNS' PROPOSED LINE EXTENSION TARIFF

Q. What modifications does UNS seek to make to its line extension tariff?

A. UNS seeks to modify its existing policy to allow for one span of overhead service conductor for each customer. UNS would also increase the total free overhead extension distance from 400 feet to 500 feet, including the service drop, for all customers. The goal of changing this tariff to allow a 500 feet free allowance is evidently to make the free allowance the same as that which TEP presently offers under its line extension tariff.

Q. Has UNS Electric performed any analysis to justify increasing the free footage allowance from 400 feet to 500 feet?

A. No. In responding to Staff data requests, it appears UNS' proposal is based solely on UNS Electric's desire to have consistent line extension policies with TEP.

Additionally, in response to a Staff data request asking UNS to calculate or estimate the revenue that would have been collected had there been no free line extension tariff in place and each customer required to advance or contribute the actual costs of extending distribution facilities, UNS states that it does not keep statistics of such information that would allow for a retroactive determination of how much could have been collected. UNS indicates that during the test year, 4,980 work orders were closed in both of its service territories, and each one would have to be examined individually to determine the revenue that would have been collected by the Company had there been no free line extension tariff in place.

Q. Has UNS Electric considered eliminating the free footage allowance altogether?

A. No. In response to a Staff data request, UNS indicates that it did not consider eliminating the free footage allowance.

Q. Does Staff support UNS Electric's proposed increase in free distribution line allowance as proposed?

A. No. UNS' witness Mr. Thomas J. Ferry states that phenomenal growth is occurring in both of UNS' service territories. During the test period, he states that customer growth increased in the Mohave County service territory by 4.8 percent and in Santa Cruz County service territory by 5.8 percent. In the past ten years, Mohave County's customer growth increased 58.5 percent, while Santa Cruz County's customer growth was 71.8 percent.

By comparison, UNS witness James S. Pignatelli states that the annual growth rate for TEP is approximately 2.5 percent, while the national average is 1.5 percent. By any measure, the growth rates for both Mohave and Santa Cruz service territories are significant.

This growth rate seems unlikely to slow anytime soon. Mr. Ferry indicates that growth is expected to continue at between five (5) to seven (7) percent annually for the foreseeable future. As soon as the Hoover Dam bypass bridge is complete, parts of Mohave County will be close enough to Las Vegas, Nevada (also one of the fastest growing areas of the country) to be bedroom communities for the Las Vegas metropolitan area. Mr. Ferry further indicates that several residential developers have announced plans to build communities of tens of thousands of homes, primarily in northern Mohave County.

Likewise, in Santa Cruz County, which contains the border port cities of Nogales, Arizona, and Nogales, Mexico, continued high growth is expected, with new developments in the Tubac and Rio Rico areas north of Nogales. "Fast Lane" commercial shipping crossings at the Mexican border have increased demand for additional warehousing facilities in the Nogales area, as Nogales has evolved into one of the major ports of entry between Mexico and the United States in the post North American Free Trade Agreement ("NAFTA") world.

Mr. Ferry states that UNS Electric has invested some $74 million in capital improvements since it took over the Citizens' system in 2003. This is a great deal of capital invested in a three-year period for a system with only 91,650 customers between the two service territories. While some of this capital has likely been necessary to improve or replace existing facilities, Staff believes a large part of this investment has been required in order to pay for the significant growth in new generation, transmission and distribution facilities.

Under these circumstances, there will be great financial pressure placed on UNS Electric to meet its increasing demand, which also will likely translate to significant upward pressure on the rates it must charge. Staff believes that UNS should use the means it has to offset its costs attributable to this growth. Staff believes that such a policy to eliminate the free footage allowance would significantly improve UNS Electric's ability to recover its distribution costs associated with this growth.

Rather than increasing a free footage allowance for new customers, Staff believes that eliminating the free footage allowance altogether by requiring new customers to at least pay the costs of the distribution lines and facilities they impose on the system will ameliorate, in part, the upward pressure on rates that such growth imposes on the system.

Staff notes that the free footage allowance was recently eliminated by the Commission for Arizona Public Service Company ("APS"), an electric utility facing similar growth rates in Arizona. Staff recommends that UNS Electric be required to submit a revised line extension tariff in Section 9 of its Rules and Regulations, eliminating all free footage allowances and setting forth the methodology by which it will bill developers and new customers for construction of new distribution facilities which are required to serve these new loads. This revision should be filed within 30 days of the issuance of the Commission's final opinion and order.

There may be individual circumstances in which elimination of all free footage allowances may impose extraordinarily harsh consequences on customers. In such cases, UNS or a potential customer could be permitted to apply to the Commission, on a case-by-case basis, for a waiver or partial waiver of this new policy.

IV. HOOK-UP FEES

Q. Please explain why Staff is addressing the issue of hook-up fees.

A. On March 28, 2006, Commissioner Mundell issued a letter in the recent APS rate case docket (Docket No. E-01345A-05-0816) requesting that the parties provide an analysis of the efficacy of using hook-up fees to help fund APS' capital expenditures so that existing customers are not continually subject to rate increases to pay for growth. Since that time a generic docket has been opened (Docket No. E 00000K-07-0052) to consider whether hook-up fees for new electric (and natural gas) customers is appropriate.

Q. Has UNS Electric done any analysis to consider whether the adoption of hook-up fees or charging a contribution in aid of construction is appropriate?

A. No. UNS indicates in response to data requests that it is participating actively in the Commission's generic docket regarding hook-up fees, but until then it is "abiding" by existing Commission regulations to use economic viability as the key determinant to extend facilities. UNS states that the actual costs of extending service lines varies considerably, but, on average, the free allowance of a single span of service and one span of distribution line for each new customer is fair and easy for customers to understand.

Q. Has Staff researched the adoption of hook-up fees for utilities in other jurisdictions?

A. Yes. Staff surveyed Commissions in other states and found that where they existed, hook-up fees were more commonly adopted for water and wastewater utilities. However, at least one jurisdiction responding to Staff's survey (Maine) adopted a policy where all new customers pay 100 percent of the distribution and transmission costs of the electric utility to serve that specific customer.

Q. Do any of Arizona's electric utilities currently have hook-up fees in place?

A. Yes. Staff is aware of two electric utilities in Arizona that utilize hook-up fees. Dixie Escalante Rural Electric Association which serves a small portion of the northeastern part of Arizona has a Commission-approved impact fee that imposes a $750 per residential hook-up for installed capacity of over 20 kW plus a $20 connect fee and $60 per kW based on the maximum installed capacity for Commercial, Irrigation, and General Service plus a $20 connect fee.

In addition, Wellton-Mohawk Irrigation and Drainage District ("Wellton"), which provides electric service to a small portion of the southwestern part of Arizona, recently adopted a $750 hook-up fee for new residential facilities plus a $29 connect fee. Wellton has indicated that hook-up fees for non-residential facilities are considered on a case-by-case basis.

Q. Is Staff recommending the adoption of hook-up fees for UNS at this time?

A. No. Though Staff may eventually explore the question of hook-up fees with UNS, at this time Staff recommends that questions related to hook-up fees be deferred to the generic docket.

V. BILL ESTIMATION

Q. Section 11, proposed paragraph 2 (pg. 79) of UNS' proposed Rules and Regulations contains certain provisions related to bill estimation. Does Staff believe that this Section adequately describes the manner in which UNS will estimate a customer's usage related to energy, demand, and time of use?

A. No. The provisions in UNS' Rules and Regulations do not address specific estimation methodologies. Staff believes that it is important to provide such information to the Commission and UNS' customers, as it will limit confusion about the manner in which UNS estimates its customer's usage.

Q. What does Staff recommend with regard to UNS' bill estimation procedures?

A. Staff recommends that UNS be required to submit through Docket Control a separate tariff describing its estimation methodologies for Commission approval within thirty days of a decision in this matter. The tariff should address energy, demand, and time-of-use estimations for situations including but not limited to the following:

a) An energy estimate with at least one year of history. Same customer at same premise or new customer with at least one year of premise history.

b) An energy estimate with less than twelve months history. Same customer at same premise.

c) An energy estimate with less than twelve months history. New customer with premise history.

d) An energy estimate. No history.

e) And energy estimate with at least one year of history. Same customer at the same premise or new customer with one year of premise history.

f) An energy estimate with less than twelve months history. Same customer at same premise.

g) A demand estimate with less than twelve months history. New customer with premise history.

h) A demand estimate with no history.

i) A time-of-use ("TOU") estimate with at least one year of history. Same customer at same premise or new customer with at least one year of premise history.

j) A TOU estimate with less than twelve months history. Same customer at same premise.

k) A TOU estimate with less than twelve months history. New customer with premise history.

l) A TOU estimate. No history. New customer at new premise.

VI. SUMMARY OF RECOMMENDATIONS

Q. Please provide a summary of your recommendations.

A. They are as follows:

1. Staff recommends that UNS be required to re-file its line extension tariff within 30 days that eliminates the free footage allowance for new construction.

2. Staff additionally recommends that the Commission take no action in this proceeding with regard to hook-up fees, but defers to the generic proceeding.

3. Staff recommends that UNS be required to file a bill estimation tariff containing specific methodologies for calculating estimates for various situations as described in my testimony, and that this tariff be filed with the Commission within 30 days of a final opinion and order.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BING EDWARD YOUNG

EDUCATION

J.D. Law, University of Idaho (1986)
B.S. (Geography), Brigham Young University (1983)
Post-Graduate Work, University of Nevada-Reno (1995)

ADDITIONAL TRAINING

Musical Production Studies, Musicians Institute, Hollywood, California (1999)
National Institute of Trial Advocacy, Two Week Litigation Seminar, New Orleans (2003)

PROFESSIONAL ASSOCIATIONS

Member of the Nevada and Utah State Bar Associations

EMPLOYMENT HISTORY

2006-2007

Arizona Corporation Commission, Phoenix, AZ, Public Utilities Analyst IV

2006

United States Census Bureau, Austin, Texas, Worked with US Census Bureau on special project being conducted in Austin, Texas.

2005

Consulting Work for University of South Carolina, Interviewed dozens of Hispanic individuals in the New Orleans area who were victims of Hurricane Katrina as part of a project sponsored by the University of South Carolina, "Latinos in the Aftermath of Hurricane Katrina".

Private Musician and Piano Bar Entertainer, New Orleans, Louisiana, Worked as private performing musician in New Orleans.

2003-2006

Royal Caribbean International, Celebrity Cruise Lines, Miami, Florida. Various contracts as piano bar entertainer aboard Royal Caribbean and Celebrity cruise ships, including CENTURY, ADVENTURE OF THE SEAS, NAVIGATOR OF THE SEAS and GRANDEUR OF THE SEAS.

2002-2003

Private Law Practice, Salt Lake City, Utah, private practice focusing on immigration law, wills and estates, personal injury, domestic relations and business law.

2001

Office of the Attorney General, State of Nevada, Bureau of Consumer Protection, worked with the Nevada Attorney General Consumer Advocate's office assisting with several matters related to electrical deregulation for the State of Nevada and legislation related thereto.

2000-2001

Consulting Attorney, Nevada Public Utilities Commission, consulting attorney for the staff of the Nevada Public Service Commission handling telephone, water, gas and electric related cases.

1996-1999

Public Service Commission of Nevada, Public Utilities Commission of Nevada, attorney for the staff of the Public Service Commission of Nevada (in Las Vegas) and later as general counsel for its successor agency, the Public Utilities Commission of Nevada (in Carson City) handling numerous public utility and transportation-related filings, as well as internal legal matters such as employment discrimination lawsuits.

1995

Nevada Public Service Commission, Part-time work for the Staff of the Nevada Public Service Commission working on cases related to small telephone and water companies while attending graduate school.

1988-1994

Nevada Power Company, worked for Nevada Power Company, Nevada's largest electric utility, in Las Vegas in positions including Assistant Staff Counsel, Staff Counsel and Associate General Counsel with responsibilities including regulatory filings and hearings, especially in the areas of environmental permitting for new power plants, transmission and distribution lines, and general and energy rate cases filed before the Commission. Also served as Manager of Resource Procurement and Administration, administering contracts with non-company wholesale energy providers and creating an RFP ("request for proposals") for contracts with potential non-utility providers of energy.

Miscellaneous

Law Clerk for District Judge Carl Christensen in Las Vegas, Nevada (1987-1988)
Law Clerk for District Judge Dan Meehl in Twin Falls, Idaho (1986-1987)
Intern, Idaho State Supreme Court, Justice Robert Huntley (Summer 1985)
Intern, United States Senate Energy and Natural Resources Committee,
James McClure (R-ID) Chairman, Washington, D.C. (Summer 1984)